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

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

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

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

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

Q. What is your formal educational experience?

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

Q. Have you previously provided testimony before the Michigan Public Service Commission ("MPSC" or the "Commission")?

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

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

- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;

- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant Power Purchase Agreement;

- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan ("IRP") pursuant to MCL 460.6t and for other relief;

- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;

- Case No. U-21090: Application of Consumers Energy for Approval of an IRP under MCL 460.6t, certain accounting approvals, and for other relief;

- 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

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

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

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.

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)

Q. What does "owned share" mean when used with respect to Campbell Unit 3?

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 784 MW capacity reported is 93% of the Campbell Unit 3 GVTC, reflecting the Company's share of ownership.

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

A. The Company owns 51% of LPS and DTE Electric Company ("DTE") owns the remaining 49%. Thus, the 1,169 MW capacity reported is 51% of the total LPS GVTC, reflecting the Company's share of ownership.

Q. Do any of the Company's owned generation units reflect retirement dates which are different from those sponsored in the Company's previous electric rate case, Case No. U-21389?

A. No. There have been no changes to the retirement dates for the Company's owned generation units. The only change to the Company's owned generation units was the addition of Heartland Wind Park which began commercial operation on December 29, 2023.

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

A. The Settlement Agreement approved in the Company's 2021 IRP reflects the replacement of the Campbell unit capacity through a number of different resources including continued growth of its solar generation assets, demand response, energy waste reduction, the acquisition of the Covert Plant on June 1, 2023, continued operation of Ludington and Karn

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

ensure it complies with all state and federal regulations. A detailed discussion of River Hydro compliance is discussed in the direct testimony of Company witness Monroe.

Consistent with the approval of the Company's Proposed Course of Action ("PCA") in its 2021 IRP, the Company will concentrate investment in new renewable energy resources, and continue investment in the existing gas-fired units as this strategy will provide the greatest long-term customer benefit. The coal-fired Campbell units will have less investment as they approach retirement in 2025. During 2023, the Company's Zeeland and Jackson Plants produced over 41% of the energy value and approximately 25% of the capacity value realized by the Company's electric generating fleet (excluding renewables). The addition of the Covert Plant on June 1, 2023 significantly increased the energy and capacity value for the Company's gas-fired generation. During its seven months of operation during 2023, the Covert Plant contributed almost 28% of the total energy value of the Company's electric generating fleet (excluding renewables) and represents over 18% of the generation fleet's capacity value. As such, the Company's investment focus and associated performance projections have been correspondingly set for these generating units. The figures below reflect the 2023 net energy and capacity value by asset type:

FIGURE 1

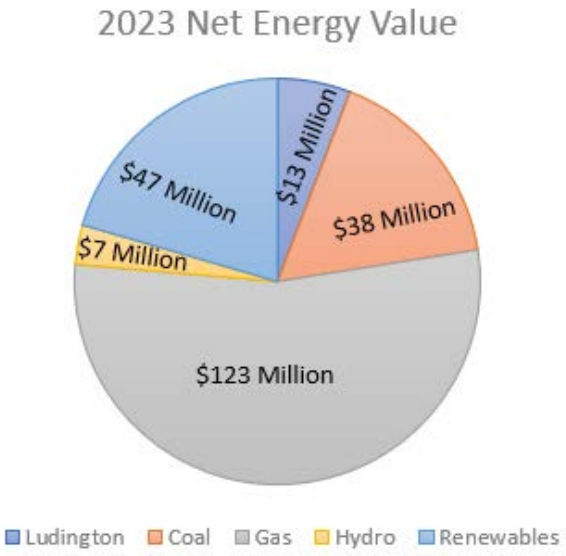
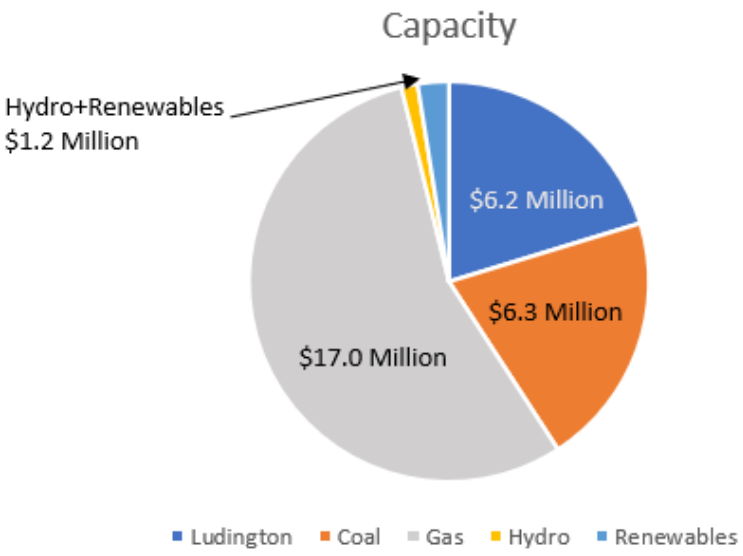


FIGURE 2



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

A. The Company's generation asset strategy with respect to the remaining generating units will vary depending on each unit's energy value, capacity value, and consistency with the Company's currently approved IRP expected retirement dates. The Company will continue

to maintain its generating units, including the River Hydro facilities, to ensure safe and environmentally compliant operations. With the exception of the River Hydro facilities, I will provide additional detail regarding the Company's generation asset strategy for each of the generating units, or group of generating units, in the portion of this direct testimony describing projected generating unit availability. Company witness Monroe will provide additional detail regarding the Company's generation asset strategy for the River Hydro facilities.

Q. Has the Company's existing generation asset strategy changed as a result of the 2023 Michigan energy legislation?

A. No. While Public Act ("PA") 235 of 2023 requires the Company to achieve a 50% renewable portfolio standard ("RPS") by 2030, the Company had already committed to an aggressive change in its generation asset portfolio mix through its 2018 and 2021 IRPs. Pursuant to PA 235 of 2023, the Company will be filing a renewable energy plan amendment no later than November 15, 2024, which will reflect its plans to comply with the new renewable energy laws.

PERIODIC OUTAGE PLANS, AVAILABILITY, ROR PROJECTIONS, AND NET ENERGY VALUE

Q. Please describe Exhibit A-41 (RTB-1).

A. Exhibit A-41 (RTB-1) identifies the major outages (28 days or longer in duration) that are scheduled during the projected test year ending February 28, 2026, for the Company's fossil-fueled and Ludington Generating Units. The Company's generation asset strategy is a key input to the scheduling of planned outages, and outage duration directly informs the periodic factors ("PFs") reflected on Exhibit A-42 (RTB-2).

Q. Please describe Exhibit A-42 (RTB-2), Generating Unit Availability Projections.

A. Exhibit A-42 (RTB-2) details Generating Unit Availability Projections for Consumers Energy's coal generation, peaking generation, and hydraulic power generation for the projected test year beginning March 1, 2025 and ending February 28, 2026. Column (a) identifies Consumers Energy's generating units or category of generating units. Column (b) identifies the five-year historical ROR of the generating unit or category of generating unit. Column (c) identifies the projected ROR of the unit or category of generating unit. Column (d) identifies the PF of the generating unit or category of generating unit. Column (e) identifies the projected availability of the generating unit or category of generating unit. Column (f) identifies the five-year historical Net Energy Value ("NEV") of the generating unit or category of generating unit.

Q. Please define ROR.

A. ROR is a measure of the percent of MWh unavailability due to forced or unplanned generating unit outages and forced or unplanned generating unit de-rates.

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

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

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

A. The ROR projections for the projected test year ending February 28, 2026 were developed from the five-year (2019-2022) average. These five-year averages were then adjusted to

reflect current operating conditions and projected unit investment. The projected unit investment is developed in accordance with the Company's generation asset strategy. These five-year historical ROR average values are presented in Exhibit A-42 (RTB-2), column (b).

Q. Please define PF.

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

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

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

Q. Please define Projected Availability.

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

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

A. The Projected Availability for each generating unit or category of generating unit is calculated as (100% - PF) * (100% – ROR). Projected Availability is the key performance metric for implementation of the Company's generation asset strategy for each generating unit or category of generating unit.

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

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

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

A. The Company can directly impact Projected Availability for a generating unit by minimizing both PF and ROR for that unit. With respect to minimizing PF, the Company can employ incremental resources during a planned outage to ensure that the critical path for the outage is as short as possible. This strategy could include working 24-hours, seven days a week, for the duration of the outage. Similarly, when a unit experiences an unplanned outage, the Company can employ necessary resources to ensure the unit is

returned to available status as quickly as practical. In addition to minimizing unforced outage length, the Company could invest in a generating unit to increase its reliability and, as a result, decrease the generating unit's projected ROR.

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

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

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

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

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

A. The Company utilizes NEV to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. These values are presented in Exhibit A-42 (RTB-2), column (f), which identifies five-year (2019-2023) actual NEV amounts.

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

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

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

A. Yes. The basis for the Company's generation asset strategy is directly related to this actuality. The Company's investment strategy is focused on those units with the lowest variable production costs to maximize NEV for its customers. As the Company strategically invests additional funds in a generating unit to increase its reliability, the

expectation is for the generating unit's reliability to be higher than otherwise possible absent the investment. Higher reliability, in turn, increases the likelihood the unit is available during periods when market prices exceed the production cost of the unit, thus increasing the NEV of the unit.

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

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

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

A. In addition to measuring NEV for a generating unit, the Company also considers the impact a higher availability (specifically ROR) will have on the amount of capacity available from a particular generating unit which receives a monetary credit in the MISO Resource Adequacy Market. Table 2 below summarizes the capacity value of the Company's generating units in the 2023-2024 PRA for Zone 7. Company witness Metz discusses the capacity value of the Company's generating units in the PRA in her testimony in this case. I will discuss the projected impact of the Company's generation asset strategy and associated capital expenditures and major maintenance on the projected availabilities, NEV, and capacity value for each of the generating units later in this direct testimony.

TABLE 2

RESOURCE	MICHIGAN LOCATION	MISO ISAC[1] MW	MISO SUMMER SAC[2] MW (ZRCs)	CAPACITY VALUE ZONE 7 (SETTLEMENT)[3]	CAPACITY VALUE ZONE 7 (75% CONE)[4]
COAL FIRED					
JH Campbell 1	West Olive, MI	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
Foote	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.

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

A. It is anticipated that the unit performance will degrade from current performance for both Campbell Units 1 and 2, and this risk will be accepted to limit new investment as the units near retirement. Based upon the Campbell Units 1 and 2 major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 16.00% at Campbell Unit 1 and 15.00% at Campbell Unit 2 in the test year, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (c). During the five-year historical period from 2019 through 2023, Campbell Unit 1 had an ROR of 16.89% and Campbell Unit 2 had an ROR of 30.27% as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (b).

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

A. The Projected Availabilities for Campbell Units 1 and 2 in the test year are 28.30% and 85.00%, respectively, as shown on Exhibit A-42 (RTB-2), lines 1 and 2, column (e). The Projected Availability for Campbell Unit 1 reflects a projected ROR of 16.00% and a PF of 66.30%, as shown on Exhibit A-42 (RTB-2), line 1, columns (c) and (d). The planned Campbell Unit 1 outage for the test year is scheduled to begin on April 1, 2025 and last for 60 days, as reflected on Exhibit A-41 (RTB-1), line 5. Projected Availability for Campbell Unit 2 reflects a projected ROR of 15.00% and a PF of 0.00%, as shown on Exhibit A-42 (RTB-2), line 2, columns (c) and (d). No outages are planned at Campbell Unit 2 for the test year ending February 28, 2026.

Q. How does the availability for Campbell Units 1 and 2 translate into customer value?

A. As reflected on Exhibit A-42 (RTB-2), lines 1 and 2, column (f), during the five-year historical period from 2019 through 2023, Campbell Unit 1 had an NEV of $94.3 million and Campbell Unit 2 had an NEV of $83.3 million. The 2023 NEV for each of these units was $6.0 million and $2.8 million for Campbell Units 1 and 2, respectively.

Q. Please quantify the capacity value for Campbell Units 1 and 2.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $1.311 million for Campbell Unit 1 and $1.452 million for Campbell Unit 2. The hypothetical capacity value upon which the Company plans its capacity resources (75% of Cost of New Entry ("CONE") for Zone 7 in the 2023-2024 PRA is $19.0 million for Campbell Unit 1 and $21.1 million for Campbell Unit 2.

Q. Please provide an overview of the generation asset strategy for Campbell Unit 3.

A. The strategic plan for Campbell Unit 3 is predicated on its planned retirement on May 31, 2025 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Campbell Unit 3 is to maintain economic dispatch and capacity value from the customer's perspective. The major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Capital projects that are targeted to improve reliability will not be considered.

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

A. It is anticipated that unit performance will remain relatively consistent with current performance. Based upon the Campbell Unit 3 capital and major maintenance projects

discussed later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 8.00% at Campbell Unit 3 in the projected test year, as shown on Exhibit A-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.

Q. Please provide an overview of the generation asset strategy for Karn Units 3 and 4.

A. The strategic plan for Karn Units 3 and 4 is predicated on their planned retirement on May 31, 2031 as reflected in the Company's 2021 IRP Settlement Agreement. The overall remaining life objective for Karn Units 3 and 4 is to maintain economic dispatch and capacity value from the customer's perspective. The capital expenditures and major maintenance expenses in the plan are targeted to provide safe and regulatory compliant units. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will not be considered.

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

A. It is anticipated that unit performance for Karn Units 3 and 4 will slightly degrade from current performance. Based upon the Karn Units 3 and 4 capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 18.00% at Karn Unit 3 and 18.00% at Karn Unit 4 in the test year, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (c). During the five-year historical period from 2019 through 2023, Karn Unit 3 had an ROR of 38.70% and Karn Unit 4 had an ROR of 24.76%, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (b).

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

A. The projected availabilities for Karn Units 3 and 4 in the test year are 72.34% and 71.44%, respectively, as shown on Exhibit A-42 (RTB-2), lines 4 and 5, column (e). The availability for Karn Unit 3 reflects a projected ROR of 18.00% and a PF of 11.78%, as

shown on Exhibit A-42 (RTB-2), line 4, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 1, 2025 and last for 42 days, as reflected on Exhibit A-41 (RTB-1), line 2. The availability for Karn Unit 4 reflects a projected ROR of 18.00% and a PF of 12.88%, as shown on Exhibit A-42 (RTB-2), line 5, columns (c) and (d). The planned outage for the test year is scheduled to begin on March 22, 2025 and last for 46 days, as reflected on Exhibit A-41 (RTB-1), line 4.

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

A. As reflected on Exhibit A-42 (RTB-2), lines 4 and 5, column (f), during the five-year historical period from 2019 through 2023, Karn Unit 3 had a NEV of -$8.1 million and Karn Unit 4 had a NEV of -$10.4 million. The 2023 NEV for each of these units was -$1.7 million and -$0.4 million for Karn Units 3 and 4, respectively.

Q. Please explain why the NEVs for Karn Units 3 and 4 are negative.

A. The NEVs for Karn Units 3 and 4 are negative due to required operation in support of capacity demonstration testing, unit performance validation, and operator training. During this operation, the units are operated as Must-Run resources in the MISO Energy Market and as such, they are price takers. In order to minimize the impact of the required operation of the units, the Company performs those activities during periods in which operation is most economic. However, despite the fact that the NEVs are slightly negative, the units provide a significant amount of capacity value, which far outweighs the negative NEV values. In addition, the Company's ability to have these units dispatched during tight generation days provides reliability benefits for the Company's customers and the MISO energy market.

Q. Please quantify the capacity value for Karn Units 3 and 4.

A. As reflected in Table 2, the capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $1.7 million for Karn Unit 3 and $2.1 million for Karn Unit 4. The hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $24.5 million for Karn Unit 3 and $30.9 million for Karn Unit 4.

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

A. The strategic plan for the Zeeland Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Zeeland Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

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

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Zeeland Plant capital and major maintenance projects that I will discuss later in this testimony, the Company's generation asset strategy is expected to result in an ROR of 4.0% at the Zeeland Plant in the test year, as shown on Exhibit A-42 (RTB-2), lines 13 through 15, column (c). During the five-year historical period from 2019 through 2023, the Zeeland Plant had ROR values at or below 7.48% for all units, as shown on Exhibit A-42 (RTB-2), lines 13 through 15, column (b).

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

A. The Projected Availability for the combined cycle generating units (Units 1 and 2) at the Zeeland Plant in the test year is 83.90%, as shown on Exhibit A-42 (RTB-2), line 13, column (e). The Zeeland Combined Cycle (Units 3, 4, and 5) Generating Unit availability is based upon a projected ROR of 4.0% and a PF of 12.60%, as shown on Exhibit A-42 (RTB-2), line 13, columns (c) and (d). The Projected Availabilities for each of the simple cycle generating units at the Zeeland site in the projected test year are 86.79%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, column (e). Each of the Zeeland simple cycle generating unit Projected Availabilities are based upon projected RORs of 4.0% and PFs of 9.59%, as shown on Exhibit A-42 (RTB-2), lines 14 and 15, columns (c) and (d). There are no outages greater than 28 days scheduled for the Zeeland combined cycle units (Units 3, 4, and 5) in the projected test year ending February 28, 2026, however there are several shorter duration outages of 10 days each scheduled in May and October. The planned outage for the test year for Zeeland Unit 1 is scheduled to begin on March 10, 2025 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 3. The planned outage for the test year for Zeeland Unit 2 is scheduled to begin on April 21, 2025 and last for 34 days, as reflected on Exhibit A-41 (RTB-1), line 6. These outages are scheduled during periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

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

A. As reflected on Exhibit A-42 (RTB-2), lines 13 through 15, column (f), during the five-year historical period from 2019 through 2023, the Zeeland Plant provided a total NEV of $220.5 million. The 2023 NEV for Zeeland was $49.4 million.

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

A. As reflected in Table 2, the Zeeland Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $4.7 million and the Zeeland Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $67.7 million.

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

A. The strategic plan for the Jackson Plant is predicated on plant operation through Planning Year 2040. The overall long-term objective for the Jackson Plant is to maintain economic dispatch and capacity from the customer's perspective. The units provide significant value to customers in both the energy and resource adequacy markets. The capital expenditures and major maintenance expenses in the plan are targeted to provide a safe, regulatory compliant, and reliable unit. Critical reliability investments required to keep the units available will be included in the plan. Projects that are targeted to improve reliability will be included in the plan if they provide value to customers.

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

A. It is anticipated that site performance will remain relatively consistent with current performance. Based upon the Jackson Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is

expected to result in an ROR of 4.50% at the Jackson Plant in the test year, as shown on Exhibit A-42 (RTB-2), line 16, column (c). During the five-year historical period from 2019 through 2023, the Jackson Plant had an actual ROR of 8.22%, as shown on Exhibit A-42 (RTB-2), line 16, column (b).

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

A. The Projected Availability for all of the generating units at the Jackson site in the test year is 81.63%, as shown on Exhibit A-42 (RTB-2), line 16, column (e). The Projected Availability for the Jackson site reflects a projected ROR of 4.50% and a PF of 14.52%, as shown on Exhibit A-42 (RTB-2), line 16, columns (c) and (d). There are no major planned outages in excess of 28 days for the Jackson units in the test year, however a short 12-day outage is scheduled to begin October 10, 2025. In addition, several derates are scheduled to perform inspections and maintenance on various generating units in April and September 2025.

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

A. As reflected on Exhibit A-42 (RTB-2), line 16, column (f), during the five-year historical period from 2019 through 2023, the Jackson units provided a total NEV of $158.4 million. The 2023 NEV for the Jackson Plant was $24.1 million.

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

A. As reflected in Table 2, the Jackson Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $2.9 million and the Jackson Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $41.9 million.

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

A. It is anticipated that site performance will remain relatively consistent with past performance under different ownership. Based upon the Covert Plant capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 7.00% for all three units at the Covert Plant in the test year, as shown on Exhibit A-42 (RTB 2), lines 17 through 19, column (c).

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

A. The Projected Availability for each of the combined cycle generating units at the Covert Plant in the test year ranges from 75.16% to 82.55%, as shown on Exhibit A-42 (RTB-2), lines 17 through 19, column (e). The Covert Unit 1 unit availability of 80.77% is based upon projected ROR of 7.00% and a PF of 13.15%, as shown on Exhibit A-42 (RTB-2), line 17, columns (c) and (d), the Covert Unit 2 unit availability of 82.55% is based upon projected ROR of 7.00% and a PF of 11.23%, as shown on Exhibit A-42 (RTB-2), line 18, columns (c) and (d), and the Covert Unit 3 unit availability of 75.16% is based upon projected ROR of 7.00% and a PF of 19.18%, as shown on Exhibit A-42 (RTB-2), line 18, columns (c) and (d). The Company will conduct major inspections at all three of the Covert Units during the bridge period/test year. The planned outage for the test year for Covert Unit 1 is scheduled to begin on February 1, 2026 and last for 59 days (beyond the test year), as reflected on Exhibit A-41 (RTB-1), line 8. The planned outage for the test year for Covert Unit 2 is scheduled to begin on February 1, 2025 and last for 59 days, as reflected

on Exhibit A-41 (RTB-1), line 1. The planned outage for the test year for Covert Unit 3 is scheduled to begin on November 1, 2025 and last for 59 days, as reflected on Exhibit A-41 (RTB-1), line 7. These outages are scheduled for periods in which energy prices are projected to be lower, thereby reducing the impact of the outages on customers. In addition, the outages are scheduled to maximize future capacity attribution for the units given the MISO seasonal resource adequacy construct.

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

A. As reflected on Exhibit A-42 (RTB-2), lines 17 through 19, column (f), during the seven-month historical period in 2023, the Covert units provided a total NEV of $49.4 million.

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

A. As reflected in Table 2, the Covert Plant capacity value based upon the settlement price for Zone 7 in the 2023-2024 PRA is $5.6 million and the Covert Plant hypothetical capacity value based upon 75% of CONE for Zone 7 in the 2023-2024 PRA is $81.7 million.

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

A. A full discussion of the Company's River Hydro generation asset strategy is included in the direct testimony of Company witness Monroe. In addition, Company witness Monroe will discuss the capital investments for the River Hydro projects which are necessary for continued safe and reliable operation. Regardless of the future of the River Hydro facilities, Consumers Energy will maintain safe operation of its hydroelectric dams as long as they are licensed by the Company. As all of the River Hydro facilities are currently licensed through at least 2034, the Company needs to continue to invest in these assets to

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

> projected capital and O&M costs through the end of Hardy Dam's current Federal Energy Regulatory Commission ("FERC") license term, with the value of the energy and capacity that Hardy Dam will provide customers, under a variety of reasonable assumptions. These assumptions will be inclusive of at least the current long-term forecast for energy prices and replacement capacity priced at a range of percentages of the Cost of New Entry. The business case shall utilize best available assumptions and consider, at a minimum, the feasibility and impacts of (i) divestiture, (ii) permanently lowering the reservoir height, (iii) full decommissioning and removal, and (iv) other options that avoid or minimize the impact of the Hardy Dam on customer rates. In addition, the Company will perform, or cause to be performed, an economic assessment of the impact of each of these scenarios on the Muskegon River Hydroelectric Dam communities.
>
> b. The Company shall engage in discussions with affected local communities on the costs and timing of the proposed Muskegon River Hydroelectric Dam projects, the need for additional funding from those Muskegon River Hydroelectric Dam impacted communities and possible mechanisms for funding to ensure FERC compliance and dam safety at the Hardy Dam, and the impact to the Hardy Dam and reservoir (as well as the Rogers and Croton dams and reservoirs) if this additional funding is not already recovered in Consumers Energy rates or received from other sources. Prior to construction of the Hardy Dam upgrades, the Company agrees to report on these discussions and inform the Commission whether additional funding from the communities or other sources is feasible (both as to amounts and timing) and provide a best-efforts estimate of the total revenue, if any, that could potentially be available from such sources."

Q. What is the status of the Company's progress on the business cases?

A. Consistent with the terms of the Settlement Agreement, the Company has commissioned the performance of business cases for the Muskegon River Hydro facilities (Croton, Hardy and Rogers) by an outside engineering firm that has experience in dam engineering, construction, and decommissioning. The business cases utilized best available assumptions

and considered divestiture (as will be discussed later in this direct testimony), full decommissioning and removal utilizing all three decommissioning options, and a permanent lowering of the reservoir height. Confidential Exhibit A-149 (AJM-7) includes the results of the business cases for the Muskegon River Hydro facilities.

In addition, the Company commissioned the performance of an economic assessment of the impact of each of these scenarios on the Muskegon River Hydro facilities communities. The results of these economic assessments are presented in Exhibit A-44 (RTB-5).

Q. Did the Company engage the MPSC Staff and the Attorney General in the development of the business cases and the economic assessments?

A. Yes. The Company met regularly with the MPSC Staff and the Attorney General to review the scope and receive input on both the business cases and the economic assessments. Through a non-disclosure agreement ("NDA"), the Company shared all relevant information related to each of the scope items, met to both present and discuss the inputs, scope, and results of each of the analyses. The Company provided formal responses to interrogatories regarding the process, data, and the results, facilitated a tour of Hardy Dam for the Attorney General, and also facilitated specific discussions on topics such as probable maximum flood ("PMF") to ensure understanding of the Hardy project design was as complete as possible.

Q. What is the status of the RFP for River Hydro divestiture?

A. The Company launched an RFP to identify potential buyers for its 13 River Hydro facilities on February 15, 2024. The RFP participants will move through a two-stage evaluation and bidding process that is expected to be complete by the end of 2024.

Q. Has the Company received responses from the February 15, 2024 RFP?

A. Yes. As part of the first phase of the RFP, which involves bidder screening based on, among other things, qualifications and indicative pricing, the Company received responses to the RFP on March 15, 2024. The Company has evaluated the bids and moved to the second phase of the RFP in April of 2024.

Q. What is the scope of Phase 2 of the RFP process?

A. Phase 2 involves engaging with seven selected entities in due diligence, negotiations, and potential sale agreement(s). Due diligence will be completed during the summer, and negotiations will take place for the remainder of the year.

Q. What is the status of the Company's discussions with affected local communities and their ability to provide funding to maintain the River Hydros?

A. To identify the potential for community funding, the Company met with local elected officials and other key community stakeholders (chamber of commerce, economic development, homeowners associations, parks department, etc.) at each River Hydro facility. The Company met several times with each community, the first meeting was to introduce the concept of community funding to the community and gauge their interest and initial thoughts on capacity. If favorable, we asked them to spend some time researching the initial options we discussed to better understand their potential capacity for funding.

The Company revisited each community four-to-six weeks later to discuss those options and truly understand the community's capacity to support its operations. At the second meeting the Company did not ask for any commitments. As a result of the meetings, the Company did identify some funding in most communities, but the available funding

was not significant when compared to the Company's current gap between relicensing and decommissioning cost estimates.

Q. What are your thoughts regarding the Company's compliance with the requirements of the Settlement Agreement?

A. As a result of the Company's collaboration with the MPSC Staff and the Attorney General, its commissioning of business cases and economic impact studies, and its economic outreach and identification of external funding, it is my opinion that the Company has satisfied the requirements of the Settlement Agreement.

Q. Has the MPSC imposed additional requirements on the Company before moving forward with construction on the Hardy Dam?

A. Yes. The March 1, 2024 Order in the Company's 2023 Electric Rate Case (Case No. U-21389) included the following requirement in ordering paragraph D:

> "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."

Company witness Monroe addresses this requirement in his direct testimony as the Company has included projected project costs for work on the Hardy Dam in this proceeding.

Q. Please describe the Company's anticipated timeline for deciding whether each River Hydro will be relicensed, sold, or decommissioned.

A. The Company intends to make a decision on the divestiture of the River Hydros by the end of 2024. Should the Company make a decision to not divest the assets, the Company

would revisit the decision to relicense or decommission the River Hydros, with the intention of making a decision in the 1st quarter of 2025.

Q. Will the Company's decision affect the need for the River Hydro investments and expenses requested in this case?

A. No. Regardless of the ultimate decision on whether to relicense, sell, or decommission the respective River Hydro facilities, the investments and expenses requested in this case are needed to appropriately maintain those facilities in order to ensure they are safe and legally compliant. The required diligence which needs to be undertaken in order to make a decision on the future of the River Hydros (e.g., adequate evaluation of the bids submitted by the seven entities which are part of Phase 2 of the RFP process and analysis of the community impact study) means that a decision on the future of the River Hydros cannot be reasonably made until late 2024 at the earliest. Subsequent activities to implement the decision(s) will extend into and beyond the test year for this case. The River Hydro investments and expenses requested in this case are needed to reasonably operate those facilities regardless of the ultimate decision on whether to relicense, decommission, or sell one or more of them.

Q. Would it be reasonable to delay approval of the River Hydro investments and expenses requested in this case?

A. No, it would not. Delaying approval of the River Hydro cost recovery in this case would mean denying the Company's ability to execute the investments and operations and

maintenance activities necessary to keep the River Hydro facilities safe and compliant with FERC regulations.

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

A. The strategic plan for Ludington is predicated on retiring the units by July 30, 2069. The Ludington units recently underwent a major overhaul that was intended to provide increased capacity and generation, increased efficiency, reduced maintenance, and an extended service life which supported the 50-year FERC license extension granted in 2019. Ludington is a FERC-regulated hydroelectric facility for which dam safety investments are identified and initiated as a result of regulatory compliance and adherence to FERC processes, including the FERC Part 12 process discussed in Mr. Monroe's direct testimony.

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

A. Based upon the Ludington capital and major maintenance projects that I will discuss later in this direct testimony, the Company's generation asset strategy is expected to result in an ROR of 3.50% for the Ludington units in the test year, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (c). During the five-year historical period from 2019 through 2023, the Ludington units had average ROR values ranging from 4.94% to 7.75%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (b).

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

A. Given the intermittent nature of solar and wind generation and the Company's plans to move to a zero net carbon future, Ludington is becoming a more critical component of the Company's generation portfolio since it can deliver a significant amount of energy in a

short time period; providing energy supply from the reservoir during periods when the wind doesn't blow and/or the sun doesn't shine. Additionally, when there is an over-abundance of wind and/or solar generation, Ludington can utilize the excess energy to fill the reservoir. Ludington's large energy storage capability greatly enables the transition to renewable energy. However, defective and non-confirming work performed by Toshiba during recent overhaul efforts must be resolved to ensure Ludington can fully provide these intended benefits over its remaining life.

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

A. The Projected Availabilities for all of the Ludington units in the projected test year ranges from 74.03% to 88.30%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, column (e). The Projected Availabilities for the Ludington generating units reflect a projected ROR of 3.50% and PFs ranging from 8.49% to 23.29%, as shown on Exhibit A-42 (RTB-2), lines 6 through 11, columns (c) and (d). There are currently no major outages planned for the Ludington units in the test year; shorter outages on all six Ludington units are scheduled throughout the test period, primarily in the spring and fall. These outages will be used, in part, to evaluate and monitor ongoing issues with the Toshiba work. The outages are scheduled during periods in which the likelihood of Ludington unit dispatch is lower, thereby reducing the impact of the outages on customers.

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

A. The Company's strategic plan for Renewable Energy Assets, both wind and solar, has been entirely driven by the Company's MPSC-approved 2021 IRP Settlement Agreement.

Consistent with the IRP, the strategy for the wind assets is to complete construction and have all wind assets in service in 2024 with the completion of Heartland Wind Farm. With respect to solar, the Company plans to continue to add incremental solar resources in accordance with its Clean Energy Plan and Renewable Energy Plan. These solar resources are being added pursuant to the Company's 2018 IRP and 2021 IRP annual solicitations, as discussed in more detail later in this direct testimony. In addition, the Company anticipates that it will also add up to 1,000 MW of wind and solar assets through 2027[1] in support of the Company's Voluntary Green Pricing Program, and their costs will be reconciled through the Company's Renewable Energy Plan. The overall investment objective for the Company-owned assets is to provide funding for projects as appropriate to maintain economic dispatch and capacity from the customer's perspective. The Company has a time-based availability target of 97% for its renewable energy wind assets. This availability target considers those periods during which the wind is sufficient to produce energy. The capital expenditures and major maintenance expenses in the plan are targeted to maintain the designed performance level.

Q. How will the enactment of PA 235 of 2023 impact the Company's renewable energy portfolio?

A. As previously discussed in this direct testimony, the Company will be filing a Renewable Energy Plan Amendment no later than November 15, 2024. PA 235 of 2023 has established both renewable and clean energy targets for the future beginning with a renewable energy compliance target of 50% in 2030. The newly passed law became

[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.

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

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.

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

("NOx") allowances allocated to the Company, so the Company will continue to monitor the rule and evaluate the various options for compliance.

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

A. Any capital and/or O&M required for the operation of the air quality control systems that the Company is seeking recovery can be found in Exhibits A-12 (RTB-3), Schedule B-5.2 and A-43 (RTB-4).

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

A. No, not at this time. The EPA released proposed greenhouse gas ("GHG") regulations for power plants under Section 111 of the Clean Air Act in May 2023. The proposed regulation covered GHG emissions from existing coal-fired and some existing natural gas-fired units. The rule does not impact the Company's remaining coal-fired units due to the May 2025 retirement date for all coal-fired units. The EPA announced in March 2024 that when the proposed Section 111 rule is finalized, scheduled for April 2024, it will no longer cover existing natural-gas fired units. EPA states that existing natural-gas fired units will be covered in a future regulation.

<u>Environmental Regulations and Compliance Strategy – Waste</u>

Q. Can you please describe the relevant parts of the Resource Conservation and Recovery Act ("RCRA") as related to Coal Combustion Residuals ("CCR") management?

A. On April 17, 2015, the EPA published 40 CFR Parts 257 and 261, Disposal of CCRs from Electric Utilities, in the Federal Register under Subtitle D of the RCRA. The rules establish

minimum national criteria for purposes of determining which CCR solid waste disposal facilities and solid waste management practices pose a reasonable probability of adverse effect on health or the environment under RCRA. The rule is considered self-implementing, meaning that affected facilities must certify compliance with the published standards and schedules. By codifying standards under Subtitle D, Owners and Operators are not required to obtain permits, and states are not required to adopt and implement the new rules. Instead, the rules' only enforcement mechanism is for a state or citizen group to bring a RCRA citizen suit in federal district court against any facility that is alleged to be in noncompliance with the newly promulgated minimum standards. In December 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act was passed. This bill provides authority for state implementation of coal ash management through a state permit program in lieu of the current enforcement of the CCR Rule through the RCRA citizen-suit authority. States may elect to submit a CCR permit program to the EPA for approval. The State of Michigan revised its solid waste statute in late 2018 to outline a state CCR permitting program. Michigan has submitted its application to the EPA for a permit program and is awaiting the EPAs review of administrative completeness. In the interim, the EPA has enforcement authority over the RCRA-CCR Rule as provided in the WIIN Act.

The existence of a state permitting program allows Department of Environment, Great Lakes, and Energy ("EGLE") to issue permits under Michigan's solid waste management statute (Part 115 of the Natural Resources and Protection Act of 1994 ("NREPA"), as amended) to regulate compliance schedules and activities for CCR landfills and surface impoundments. Although the current state CCR permitting program was

passed into law and Consumers Energy is obligated to comply with the associated statute, permits, and licenses, the program must be approved by the EPA on the basis that it is "as protective as" the CCR Rule to avoid dual state and federal regulation. Thus, similar compliance standards are required within the state permitting program, including requirements to make compliance documentation publicly available, completing the work, and then self-reporting by providing notifications to EGLE and posting to a publicly accessible compliance website.

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

A. The Company's CCR management compliance strategy was approved in Case No. U-18322. The major capital work for compliance has been completed. The Cost of Removal ("COR") and/or O&M required for the management of CCRs under the RCRA that the Company is seeking recovery of can be found in Exhibits A-122 (JJK-3) and A-42 (RTB-4). The COR expenses represent historical expenses only. Separately, there are closure activities that will continue throughout the bridge period and test year and beyond; however, those expenses are COR and are not included in this filing.

SECTION III
GENERATION CAPITAL EXPENDITURES
OVERVIEW

Q. What factors does the Company consider in determining the capital investments that it will make at its generating plants?

A. The major drivers in the determination of generation capital investments are plant safety, compliance with regulations, and reliability. Consumers Energy's strategy for complying with environmental regulations was previously discussed in this direct testimony.

Q. Please describe Exhibit A-12 (RTB-3), Schedule B-5.2, Generation Capital Expenditures.

A. This exhibit presents the capital expenditures for Generation, 2023 through the projected test year - 12 months ending February 28, 2026. Exhibit A-12 (RTB-3), Schedule B-5.2, is a nine-page exhibit. Page 1 of this exhibit presents a summary of Generation capital expenditures for the Historical Period ended December 31, 2023, the Projected 14-month Bridge Period beginning January 1, 2024 and ending February 28, 2025, and the projected test year beginning March 1, 2025 and ending February 28, 2026. This summary information is broken down by Steam Power Generation, Hydraulic Power Generation, Pumped Storage Generation, and Other Production Plant. Pages 2 through 5 of this exhibit capture the same Historical Year, Bridge Period, and Test Year Generation capital expenditures information, but is presented by generating sites and environmental categories. This information is further detailed by Contractor, Labor, Materials, Business Expenses, Contingency, and Other. Page 6 of this exhibit represents a summary of pages 2 through 5 of this exhibit. Finally, pages 7 through 9 of this exhibit identify the capital projects and associated expenditures that are greater than $1 million that contribute to the overall capital expenditures summarized on pages 1 through 6 of this exhibit. Specifically, page 7 of this exhibit presents capital projects for the Historical Period ended December 31, 2023; page 8 of this exhibit presents capital projects for the Projected 14-month Bridge Period beginning January 1, 2024 and ending February 28, 2025; and page 9 of this exhibit presents capital projects for the projected test year ending February 28, 2026.

Q. What project information is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9?

A. Exhibit A-12 (RTB-3), Schedule B-5.2, pages 7 through 9, presents the generation type, the generation unit, project type, project classification, project description, and project cost information. The project type identifies whether the project is routine or non-routine. Routine projects include work that is performed regularly; whereas, non-routine projects are typically undertaken once every 10 years or longer. The budget approval reflects the status of internal approval for the project, including projected cost amount. Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, includes both projected and actual capital project cost; whereas, Exhibit A-12 (RTB-3), Schedule B-5.2, pages 8 and 9, includes only the project projected amount.

Q. What level of capital spending for generating plants does the Company request the Commission to incorporate into rates in this case?

A. The Company's rate relief request in this case reflects capital spending on projects for its generating plants of $859.095 million for the historical test year ended December 31, 2023 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (b); $463.548 million in the projected 14-month Bridge Period ending February 28, 2025 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (e); and $600.484 million in the projected test year ending February 28, 2026 as shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, line 17, column (f).

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

A. No. The Company no longer includes contingency in its generation projects.

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

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

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

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

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

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

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

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

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

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

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

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

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

A. The cause of each of the historical events impacting availability are evaluated and measured, and the actions necessary to avoid the same or similar events are considered for implementation. In many cases, actions necessary to prevent the event from recurring are cost beneficial. The availability projections, including ROR, simply reflect the Company's best estimate of the operational benefits of those corrective actions that have already been taken or are planned to be taken, through the projected test year ending February 28, 2026.

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

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

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

A. Yes. The Company often forecasts future actions and capital expenditures based on currently available information, many months before the work is completed. To provide some perspective, the outage schedule used in this case was approved in August 2023. A review of the outage schedule used in this case identifies eight scheduled outages that begin in March 2025 (18 months after the schedule was approved) and run through

February 28, 2026, 29 months later. During each of these eight scheduled outages, Consumers Energy has scheduled a number of tasks to be performed. Because of the long lead times, the number of outages scheduled during the test year, and the fact that several different tasks will be performed during each outage, it is inevitable that some scheduled outages and forecast capital expenditures will change. However, the Company has a history of prudent capital investments in its generating facilities, which have been consistently supported by the Commission.

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

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

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

A. Yes. The Company's fall 2023 outage for Campbell Unit 1 was originally scheduled from October 13, 2023 through November 12, 2023. The unit was placed into economic reserve status on February 19, 2023 and subsequently began a maintenance outage on March 7, 2023. The maintenance outage lasted for 14 days, ending on March 21, 2023. During this timeframe, all priority work scope that was scheduled for the fall outage was completed, obviating the need for the planned outage scheduled to begin on October 13, 2023.

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

A. Consistent with the Company's generation asset strategy, generation projected capital investments support the continued safe, regulatory compliant, and reliable operations of the Company's electric generating fleet. Projected capital investments are informed by

historical and anticipated performance of the units. The reasonableness of the generation capital investments is indicated by the sustained or improved performance of the Company's electric generating fleet relative to: (1) the safety of the employees, contractors, and community at and around the generating facilities; (2) compliance with rules and regulations; and (3) reliably participating in the energy, resource adequacy, and ancillary services markets.

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

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

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

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

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

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

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

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

2023 HISTORICAL TEST YEAR CAPITAL EXPENDITURES

Q. How does the 2023 actual capital expenditure amount of $859.095 million compare to the amount of capital expenditures reflected in the Company's request in Case No. U-21389?

A. The 2023 actual capital expenditure amount of $859.095 million is $430.277 million below the Company's requested amount in Case No. U-21389. The reduction in the Company's actual capital expenditure amount is directly attributable to the removal of the capital expenditures for IRP solar projects and the actual accounting treatment of the Covert purchase. While the Covert total purchase cost was consistent with projections, the total amount was not recorded as an addition to plant in service. The actual amount recorded as capital was $151.858 million less than the projected purchase amount as can be seen on

Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 3, columns (g) and (h). The projected amounts for the 2019 and 2020 IRP Solar Bid Events totaled $355.250 million in the Company's 2023 Electric Rate Case No. U-21389 (see Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, lines 38 and 39, column (n)), however these amounts were removed from the case due to their project status. The projected solar project capital expenditures were not projected to close by the end of the projected test year and were offset by the allowance for funds used during construction ("AFUDC"). As such, the underspend did not impact the revenue requirement. A compilation of the 2023 projects which have actual capital expenditure amounts greater than $1 million is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

Q. How does the compilation of capital projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, compare with the 2023 capital projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9?

A. A comparison of the projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, with the 2023 projects reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, reveals that there are seven projects on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, which were not reflected on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9. In addition, there were twenty projects for 2023 that were reflected 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.

Q. Please discuss the 2023 capital projects that were included on Case No. U-21389, Exhibit A-12 (RTB-3), Schedule B-5.1, page 9, that are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7.

A. The following projects are not presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, due to the fact that their actual 2023 capital expenditure amount was less than $1 million, the project was disallowed, reduced in cost, or not pursued in 2023. The disposition of these capital projects is provided below:

Below is a list of projects whose projected bridge period costs were disallowed in the final order in Case No. U-21389:

Project Description	Projected Amount
Covert Non LTSA Capital - Extras not included in contract	$ 3,942,510
Karn Tank Farm Storage Tank Heating Line Replacement	$ 1,253,971
Karn Sync Wire Replacement	$ 1,450,000
Alcona Core Wall Remediation Project	$ 1,810,370
Rogers Probable Maximum Flood Project	$ 1,898,708
2019 Solar Bid Event – Mustang Mile	$ 233,064,275
2020 Solar Bid Event – Washtenaw	$ 122,186,164

Below is a list of projects whose projected bridge period costs were reduced or deferred by the Company and their projected amounts approved in the final order in Case No. U-21389 were less than $1 million:

Project Description	Projected Amount	Project Reduction
Webber Unit 1 Generator Rewind	$ 1,020,000	$ 1,020,000
Zeeland Milestone Outage Capital to GE - Part of LTSA Contra	$ 7,870,000	$ 7,870,000
Zeeland Unit 4 Field Rewind of Generator Rotor	$ 1,205,357	$ 1,205,357
Zeeland Unit 3 Field Rewind of Generator Rotor	$ 1,205,357	$ 1,205,357
Cooke Spillway Hoist Replacement	$ 2,100,000	$ 1,492,000
Zeeland Phase 2 599 699 345kV Breaker Replacement	$ 1,222,915	$ 773,000
Ludington Oil Water Separator Replacement	$ 1,162,917	$ 679,000
Ludington Unit 1-6 DCS Control Relay Replacement	$ 1,347,516	$ 727,000

Below is a discussion of the remaining million-dollar projects whose actual 2023 capital expenditures were less than projected:

- Zeeland Heat Recovery Steam Generator ("HRSG") Casing Replacement ($2,803,333). This project is scheduled to be completed in 2024. The Company

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;

- Covert Spare Generator Stepup ("GSU") Transformer ($1,722,987). The scope of this project is the procurement of a spare transformer for the Covert Generating Station. The 2023 capital expenditure reflects a milestone payment to the best identified bidder and internal loadings. This project will be discussed in more detail later in this direct testimony;

- Karn Units 3 and 4 Boiler Plant Heating ($4,836,052). The Karn Units 3 and 4 Plant Heating Boilers Project was a strategic initiative aimed at upgrading the plant heating system at Karn Power Station. The project involved the procurement and installation of two smaller, more efficient boilers for continuous plant heating. Prior to implementing this project, the existing 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 Exciter Rewind ($1,038,719). The scope of this project was to remove the Karn Unit 3 Exciter Rotor and send it out to be rewound. This work was required as a result of the main lead in the exciter rotor failing open. Once the exciter was disassembled at the vendor facility, the broken lead and the resulting inability to excite was identified. To repair the broken main lead, a full rewind was needed because the main lead was buried under the windings;

- Jackson Multimedia Filtration Pilot Skid ($2,441,755). The scope of this project was to perform testing and calibration as well as provide system improvements to the treatment systems for the well water. The specific scope of the project includes the installation of larger bleach pumps in order to pump a higher flowrate of bleach to counteract the bleach degradation, replacement of caustic pumps on caustic injection system due to issues with pump performance, replacement of variable frequency drive and breaker damaged by caustic injection system, replacement of control valve on well water forwarding pump to increase the flowrate up to the required 1,150 gpm, adjustment of the logic in the reverse osmosis pretreatment system to remove ability for all (4) beds to backwash at the same time, run various scenarios to optimize the throughput of the greensand filters, the caustic in the pretreatment, and the bleach in the pretreatment, and other system improvement activities;

- Zeeland Unit 5 GSU Transformer Rewind ($13,884,854). The scope of this project was to remove the failed Zeeland Unit 5 GSU transformer, movement and installation of the spare GSU transformer, and sending out the failed Zeeland Unit 5 GSU transformer for overhaul which included milestone payments for the overhaul. In addition, the scope reflected the monthly lease of a spare transformer to provided continued operation of the unit for customers. Zeeland Unit 5 was taken out of service on December 17, 2022 and was returned to service on January 23, 2023 upon installation of the leased transformer which was moved from Zeeland Unit 1; and

- 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

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

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.

Q. Is the projected capital expenditure amount of $463.548 million for the 14-month bridge period ending February 28, 2025, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (e), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (h), $249.572 million of that capital will fund solar projects pursuant to the Company's IRP, $39.672 million will fund BESS projects, $118.854 million of that total capital expenditure amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $10.279 million will fund various projects at the LPS facility, and $42.376 million will fund various hydro safety, reliability, and regulatory compliance projects. With the exception of the solar, BESS, and the River Hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The River Hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

PROJECTED TEST YEAR CAPITAL EXPENDITURES

Q. Is the projected capital expenditure amount of $600.484 million for the test year ending February 28, 2026, on Exhibit A-12 (RTB-3), Schedule B-5.2, page 1, column (f), consistent with the Company's generation asset strategy?

A. Yes. Based upon a review of the projected capital expenditure presentation on Exhibit A-12 (RTB-3), Schedule B-5.2, pages 2 and 3, lines 1 through 99, column (j), $275.959 million of that capital will fund solar projects pursuant to the Company's IRP, $78.921 million will fund BESS projects, $134.664 million of that total capital expenditure

amount will be used at the Company's natural gas generating facilities which includes Covert, Jackson, Zeeland, and Karn Units 3 and 4. In addition, $15.587 million will allow the Company to complete various regulatory, reliability, and infrastructure projects necessary to support the 50-year license extension at Ludington granted by FERC in 2019 and $92.258 million will fund various hydro safety, reliability, and regulatory compliance projects. Except for the solar projects and the River Hydro projects, a detailed discussion of the various projects for each generating unit or group of generating units will be provided later in this direct testimony. The River Hydro projects will be discussed in the direct testimony of Company witness Monroe and the solar projects will be discussed in the direct testimony of Company witness Clark.

Campbell Units 1, 2, and 3

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 Campbell Units 1, 2, and 3.

A. The Company does not plan to invest any capital in the Campbell units during the bridge period or test year, as reflected on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, lines 1 and 8. As presented on Exhibit A-43 (RTB-4), lines 1 and 2, and as discussed later in this direct testimony, the Company has projected modest amounts of major maintenance to ensure that these units are able to operate through their retirement date of May 31, 2025.

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;

- 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;

- 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;

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;

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

advancement. Covert, which has been operational since 2004, faces significant challenges with its Emerson Ovation DCS. The system's obsolescence, cybersecurity risks, and operational inefficiencies necessitate an urgent upgrade to the latest version to enhance reliability, security, and compliance with regulatory standards. The DCS that controls all equipment in the plant (along with the Mitsubishi gas turbine controls), is Emerson Ovation DCS. It was upgraded about 10 years ago to the current version. Emerson Ovation version 3.5.1 is no longer supported by Emerson or Microsoft. The Emerson Ovation version 3.5 system entered a retired status in June 2019. The Windows operating systems that are used by this version of Ovation are Windows 7 and Windows Server 2008R2. Microsoft ended extended support of Server 2008R2 in January 2020.

The generation plant control systems are an important part of the nation's Critical Infrastructure and fall under NERC CIP requirements. To keep the Company's control systems secure, Consumers Energy must patch the operating systems and applications that run its plants. The Company is no longer able to patch and maintain these operating systems, such as Microsoft Windows, or applications, such as Ovation, when they are no longer supported by the manufacturers. The systems at Covert do not meet corporate cybersecurity standards and are operating with security exception to the Company's standards.

The cybersecurity tools (Power Water Cybersecurity Suite ("PWCS")) being utilized for the Covert control network device patching and antivirus protection require replacement to allow continued patching and protection with a new DCS version. The current version of PWCS is nearing end of support and requires updating to allow support of the latest Ovation versions.

The Balance of Plant ("BOP") control is achieved with the Ovation DCS. Its architecture is comprised of controller and operator "drops" (processors and PCs) that provide the control of the equipment with input/output ("I/O") modules. Some of these I/O modules are in the same electrical cabinets that contain the "controller drops" (processors). Other I/O is in "remote" electrical cabinets, away from the "controller drops." The existing plant control is comprised of many remote I/O cabinets throughout the site. The communication modules to these cabinets have experienced failures in the past that can trip the generating units offline. Power supplies in the Ovation cabinets have reached the end of their recommend life and need to be replaced. The architecture and components need to be upgraded and replaced with the latest Ovation design.

The main controller drop that operates a large part of the BOP equipment has had equipment and data link controls added to it over the years. It controls equipment for all three (3) generating units. The controller drop needs to have part of its I/O and logic split off to new controller drops. The partitioning of I/O

to other drops should allow the upgrade and maintenance procedures to occur and reduce the need of a site outage to perform these activities. Risk to unit trips should be reduced to individual generating units instead of all units on the site;

- Netmation (Operating System and 4S) – Unit 3 ($1,504,167). 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 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 Plant LTSA ($14,700,000). This is the capital portion for Mitsubishi negotiated services that cover the planned normal maintenance of each generating unit. The projected capital expenditures are based upon variable fees paid to Mitsubishi for maintenance services which are based on an Effective Fired Hour basis pursuant to the LTSA. Unlike the GE LTSAs for the Jackson and Zeeland plants, there are no milestone payments associated with the fee structure for the Mitsubishi LTSA. Based on the OEM's operating and historical experience, if the Company executes the normal planned maintenance and inspections according to the recommended schedules, the Company will mitigate unexpected pre-mature failures of the equipment. This will help maximize availability and, as a result, optimize customer value for the site. Normal maintenance will ensure the Company continues reliable operation of the units. During the bridge period and test year, the Company will be conducting major inspections on all three generating units, and a portion of the work to be performed is not covered in the LTSA, rather it is covered in the LTSA extra work as described below;

- Covert Unit 1 LTSA extra work ($1,437,717). 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. The major inspection for Covert Unit 1 begins on February 1, 2026, just prior to the end of the test year, and ends on March 31, 2026. As such, a large portion of the LTSA extra work will not be requested in this proceeding;

- Covert Unit 2 LTSA extra work ($12,609,633). 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. The major inspection on Covert Unit 2 begins on February 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with Mitsubishi Electric Power Products, Inc. ("MEPPI") does not cover this scope of work; and

- Covert Unit 3 LTSA extra work ($10,609,633). 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. The major inspection on Covert Unit 3 begins on November 1, 2025, and major work includes generator inspection, replacement of the generator hydrogen seals, generator rewedge, diaphragm repairs, steam turbine and generator bearing repairs, and HP stop and control valve disassembly, inspection, cleaning, and repair. The Company's LTSA with MEPPI does not cover this scope of work.

The following projects are less than $1 million, but are important to reliability:

- Excitation Replacement ($761,667). The scope of this project is the replacement of the steam turbine exciters. The existing excitation equipment is obsolete, and the gas turbine exciters have already been replaced. A failure of the steam turbine exciter could lead to both generators on the unit being out of service until replacements can be found with a typical lead time of 18-24 months;

- Electronic Overspeed protection ($678,333). The scope of this project is the installation of an electronic overspeed trip upgrade. The plant has experienced issues with their overspeed trip device in the past. The backup electronic overspeed trip is reliable but is not redundant so that a single component failure would not disable the trip. The primary protection on the steam turbines are the mechanical overspeed trip mechanisms. The mechanical overspeed trip mechanism must be tested (offline) periodically to ensure that its setpoint has not changed and that it can trip the unit;

- Flame Detectors for Gas Turbine Wheel temperature Digital replacement ($397,083). The scope of this project is to replace the existing mechanical flame detection system with digital flame detection system. The existing

system is obsolete and has reliability issues that a new digital system would resolve;

- SCR/CO Catalyst Replacement - Unit 2 ($708,333). 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;

- SCR/CO Catalyst Replacement – Unit 3 ($708,333). 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;

- Netmation (Operating System and 4S) – Unit 1 ($375,000). 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;

- Balance Of Plant Valves – Unit 2 ($590,000). The scope of this project is the repair and/or replacement of balance of plant valves. The plant has a long list of valves that require attention. The condenser bypass valves will be addressed in the major outage scheduled for March 1, 2025 through March 31, 2025 and they represent a large expense;

- Balance Of Plant Valves – Unit 3 -($590,000). The scope of this projects is the repair and/or replacement of balance of plant valves. The plant has a long list of valves that require extensive maintenance. The condenser bypass valves will be addressed in the major outage scheduled for November 1, 2025 through December 30, 2025 and they represent a large expense;

- Positioning Sensor – Unit 3 ($687,500). 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, 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.

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.

Q. Did the Order in the Company's 2023 Electric Rate Case (Case No. U-21389) establish any specific requirements for any of the Karn site projects?

A. Yes. Paragraph C on page 309 of the March 1, 2024 Order in Case No. U-21389 required the following:

> "Consumers Energy Company shall file in its next general electric rate case an alternatives analysis addressing the replacement of the Karn Unit 3 Cooling Tower internal structure, including information on the most cost-efficient solution and alternatives to full replacement as described in this order."

Q. What is the scope of the project?

A. The scope of this project is the replacement of the structural timbers, remaining stacks, and fan blades on Karn Unit 3's cooling tower. The wooden structure is original equipment and has decayed since its installation. The cooling tower provides cooling water for the condenser. The wooden cooling tower structure supports 18 large fans that pull air through the water to drive the evaporation process to cool the water. The wooden structure also supports large water pipes that carry the cooling water to the fill. The water flow to the tower is approximately 240,000 gallons per minute. The entirety of this weight is supported by the wooden structure as it is conveyed to the tower and cascades over the fill. Implementation of this project will provide for reliable operation of Karn Unit 3 through its retirement in 2031. The projected cost for this project in the 14-month bridge period is $6.0 million.

Q. Has the Company performed an alternative analysis?

A. Yes. The Company has created a concept approval to document its evaluation of the project and the potential alternative. The concept approval is presented as Exhibit A-45 (RTB-6).

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

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;

- 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.

Q. What is the basis for the projected $7.287 million capital investment in the projected test period?

A. The projected $7.287 million capital investment in the projected test period will fund five projects. Two of these projects are greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 18-19. The basis for these projects is described below:

- Karn Unit 4 Replacement of Ductwork Insulation and Lagging ($4,800,000). The scope of this project is to replace the lagging and insulation on all the ductwork from the building out to the stack. The existing lagging and insulation needs to be removed, the underlying steel fixed as necessary, and new insulation and lagging installed. The steel structure that the ductwork lagging is attached to is severely corroded. This has allowed multiple random failures of the lagging, resulting in a safety concern due to pieces of lagging falling to the ground or becoming airborne during wind events; and

- Ductwork Expansion Joint Replacement – ID Fans to Stack ($1,900,000). This project will replace all expansion joints and entry doors between the ID Fans and the stack. All expansion joints between the ID Fans and the Stack are beyond their end of life and suspected to be severely degraded based upon the condition of expansion joints found during the Karn Unit 3 Breeching project. Failed expansion joints will need to be replaced to maintain environmental compliance. This scope of work will make the ductwork air-tight again to maintain environmental compliance.

The following projects are less than $1 million, but are important to reliability:

- Capital tooling/valves/instrumentation ($500,000). This project supports capital expenditures for replacement of small valves, instrumentation, tools, equipment, pumps, and motors at Karn Units 3 and 4 during the projected test year; and

- Two additional projects at Karn Units 3 and 4 totaling $0.087 million which support reliability, with each project representing $66,667 or less in capital expenditures. These projects include overhaul of the Karn Unit 4 condenser circulating water pumps and project closeout of Karn Units 3 and 4 sync wire replacement.

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

outputs electricity from the generator to the grid, was showing signs of imminent failure as indicated by hydrocarbon gasses being continuously generated at rates above Institute of Electrical and Electronics Engineers (IEEE) recommended levels. The time to failure could not be predicted and could have been catastrophic in nature. Previous intrusive internal inspection and testing work in fall of 2022 was able to identify and replace some degraded parts but ultimately not able to locate the source of gas generation;

- Zeeland Plant HRSG Casing Replacement ($2,097,620). The HRSG is designed to recover and recycle heat energy from a gas turbine exhaust. A HRSG produces steam that is used to drive a steam turbine. During recent inspections of the HRSGs at the Zeeland Plant, extensive outer casing corrosion has been identified in particular sections of the units. This condition creates the risk of the studs, which hold on the insulation and liner panels, breaking loose and liberating both insulation and liner sheets. The insulation then blows downstream and fouls the HRSG tubes, requiring the unit to be shut down and cleaned, then subsequent casing, insulation, and liner repairs. The affected areas of casing need to be cut out and replaced with new casing; and

- Zeeland Plant LTSA supplementals not included in contract ($3,925,000). 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.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Main Steam Non-return Valve Replacement ($705,309). The scope of this project is to replace both main steam check valves. During inspections in the Fall 2018 outage, cracking was noted on both of the main steam stop-check valve body internals. With continued plant operation, the cracks are expected to continue to grow, potentially extending through the valve seat, making the valve unable to seal completely. The cracks can also grow to a through-wall crack, resulting in a steam leak. This cracking is a known issue with these types of valves, and is driven by expansion differentials primarily on startup and shutdown. This cracking had initially been noted during a pipe borescope inspection in 2011;

- Zeeland - Purchase of Site Spare GSU Transformer ($589,607). 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;

- 199 and 499 345kV Breaker Replacement ($623,483). The scope of this project is to replace the 199 and 499 circuit breakers with a type which does not exhibit the failure modes exhibited by the existing design. The existing breakers have a critical design flaw such that an individual pole or poles may not latch open

when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland Substation, and/or equipment damage;

- Site Commons Road Resurfacing ($554,167). 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;

- Gas Turbine Inlet Filters Replacement ($390,000). The scope of this project is to replace canister filters. The filters are required to be replaced every five years and must be accomplished during an outage. The purpose of the project is to maintain the integrity of the filters to prevent material ingress to the turbines;

- ZGS – GE DCS Evergreen ($600,000). The scope of this project is to upgrade the Zeeland Plant Turbine Controls DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system which was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. This project will allow the latest versions of control software and operating systems to be used for reliable operation and control of the generating units. The latest feature enhancements are also available for operation. This will also allow the latest patches to be applied by the cyber security Emerson PWCS application. The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. The vendor life cycle for DCS versions is generally five years. After five years they enter a retired state and are no longer patched. Microsoft Operating Systems are on a limited life basis, and they reach the end of "extended support" and no longer get security patches;

- ZGS – 299 345kV Breaker Replacement ($510,000). The scope of this project is to replace the 299 circuit breaker with a type which does not exhibit the failure modes exhibited by the existing design. The existing breaker has a critical design flaw such that an individual pole or poles may not latch open when required. The pole's failure to latch open has the potential to result in lost generation, loss of power to the entire Zeeland substation, and/or equipment damage;

- Zeeland Plant Base Outage Capital ($482,555). 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

- Seventeen additional projects at the Zeeland Plant totaling $2.617 million supporting safety, reliability, regulatory compliance, infrastructure, and operations, with each project representing less than $337,200 or less in expenditures. These projects include Install Combustion Turbine Overspeed Software, Phase 2 599 and 699 345kV Breaker Replacement, Zeeland combined cycle GT2A GT2B Air Filter Replacement, MarkVIe Controller Replacement Project, 480V Circuit Breaker Coordination System Replacement,

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

market value for Consumers Energy and its customers. For the Zeeland combined cycle plant, the combustion turbine requires the operation of the steam turbine, therefore the loss of the steam turbine's GSU transformer would effectively limit operation of two connected combustion turbine units. The lead time for a GSU transformer is currently three-to-four years and spare units at other facilities are not viable replacements due to compatibility and installation challenges. This project would purchase a spare GSU transformer that is sized to be able to replace any of the existing transformers on site and develop redundancy for any minor power upgrades in the future. As previously discussed, the GSU transformer for Zeeland Unit 1 has failed and is being sent out for rewind;

- Phase I Gas Turbine Advanced gas path replacement and axial fuel staging ($25,743,740). The scheduled Major Inspection outages in 2025 for the Phase 1 gas turbines at Zeeland Generating Station present an ideal time for substantial technological advancements. This project proposes the integration of Advanced Gas Path ("AGP") and Axial Fuel Staging ("AFS") technologies during these outages, aimed at boosting turbine performance and operational flexibility. A more detailed analysis of this project is presented in Exhibit A-46 (RTB-7): Zeeland Phase 1 Gas Turbine upgrades;

- Generator Rewinds ($2,174,167). There are multiple Technical Information Letters (Bulletins) from the OEM (GE) involving the brazed connections under the retaining rings that need to be addressed as well as multiple turn shorts potentially evident by the OEM 2021 health assessments for Zeeland Units 3 and 4. The impacts of turn shorts include: uneven heating of the rotor which will lead to increased seismic vibrations that can create multiple failure scenarios for a field and possible induced rotor bow, higher field current required to match original design which can result in higher heating effects and escalated failure modes, and damage to the retaining rings which will further escalate the vibrational issues. During the major overhaul, the generator rotors will be removed and replaced/rewound, correcting the issue with the connections and shorted turn issue, allowing the units to run to the anticipated end of life; and

- Phase II Turbine Replacements ($1,884,167). The scope of this project replaces the existing rotor with a new rotor, giving another 144,000 hours of operation which would enable operation until the next rotor replacement out to approximately the year 2045. Also included in this scope is new compressor stator vanes due to the compressor being 20 years old; the best way to restore the compressor to like-new condition is to replace the stationaries when the blades will already be replaced. Lastly, the exhaust frame will be upgraded to a robust exhaust frame due to reliability issues over the years, and the rotor replacement being an appropriate time to replace the exhaust frame.

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.

Q. What is the basis for the projected $19.130 million capital investment in the 14-month projected bridge period?

A. The projected $19.130 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 7-8. The basis for these projects is described below:

- Jackson Plant LTSA ($12,337,500). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant; and

- Jackson Plant LTSA Extra Work ($2,908,333). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of projected test year capital projects for the Jackson Plant.

Several other critical projects which are less than $1 million but are important to reliability and infrastructure include:

- Feedwater Desuperheater Valve Replacement ($831,433). The scope of this project is to install feedwater control valves and separate lance spray nozzle assemblies that spray small amounts of water into steam flow continuously. The HRSG 1-6 superheat ("SH") Steam Desuperheater Feedwater valves have had very short life spans since original construction. There are several issues that cause the valves to wear out quickly. The valves inherently cycle frequently open and closed due to the boiler running close to high pressure ("HP") Steam Outlet temperature setpoint at gas turbine baseload, without duct firing. This has been reduced recently by a study completed by engineering and GE to allow the HP Steam temperature to be increased from the original 750 degrees Fahrenheit up to 770 degrees Fahrenheit. This change did cause the valves to cycle open/close less frequently, but it did not result in a substantial improvement in valve life. The brunt of the wear is absorbed by the HP FW Autoblock valve, which when it begins to leak by, causes the SH Steam temperature to fall. The HP FW Control Valve wears out quickly as well. Typically, when this occurs the leak by accelerates quickly to the point which the manual HP FW isolation valve upstream must be closed when the unit is not duct firing in order to maintain adequate superheated steam temperature;

- 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

sump pit has two pumps that operate off a multi-float switch level indicator. The level indicators are reaching end of life. The water treatment LQ pumps have a mean time between failures of about one year. The HQ sumps were upgraded in 2019 with no failures at this time. The failures on the water treatment sumps are due to failed bearings, worn impellers, volutes, and casings. There is a large amount of dirt, oil, and other debris that get into the water treatment LQ sump leading to wear of pump components and bearing failures. The scope of this project is to replace the two sump pumps in the water treatment LQ sump and the level indication on both LQ sumps. It is recommended to install pumps with upgraded wear materials to help with the erosion issue and install sealed greased bearings. The level transmitters are also beginning to fail as the switches do not always actuate when they are supposed to. The level transmitters will be replaced with radar level transmitters. The sumps are locally controlled with an audible alarm. This project would also bring control and level indication into the DCS for the sump;

- JGS NOx Umbilical Replacements ($300,728). The scope of this project is to replace the heated sample line (umbilical) on Jackson Units 1 through 5 and 7 from the analyzer to the stack probe. The Continuous Emissions Monitoring System ("CEMS") and associated umbilicals have been in service since 2002. As a result of the heat trace failure on the LM6 umbilical in 2020 and the visual condition of the polyurethane jacket, the remaining umbilicals were inspected. Similar cracking and poor installation practices were observed. To avoid unit downtime in the future, the Company determined that a project should be initiated to replace the remaining units' umbilicals. A three-year implementation plan, replacing two umbilicals per year, is proposed to mitigate risk. The new umbilicals will utilize a PVC jacket that is more resistant to degradation and chemical attack. Post maintenance testing will be required upon replacement including a relative accuracy test audit ("RATA") to recertify the CEMS. The combined-cycle combustion turbines at Jackson are subject to specific NOx emission limits and monitoring requirements originating from several environmental rules. For purposes of demonstrating compliance with the NOx emission limits, JGS relies upon CEMS for each unit;

- Jackson Combustion Turbine Inlet Canister Filter Replacement ($230,000). The Jackson Plant is comprised of nine generating units. Jackson Units 1 through 7 draw combustion air in through a filter house which has integrated filters to prevent dust, dirt, and debris from being pulled into the compressor section of the turbine. The canister filters require periodic replacement to maintain proper air flow to the engine. Over time the filters plug and reduce the efficiency of the combustion turbine. If air flow is restricted enough, the engine can stall due to lack of sufficient air causing catastrophic failure; and

- 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;

- Base Outage Capital ($300,000). Base outage capital covers the replacement parts and issues found during turbine/generator inspections and the major discovery issues found during annual unit outages;

- JLM1-6 Variable Inlet Guide Vane ("VIGV") Project ($900,000). This project will install new VIGV systems on six LM6000PC engines at the Jackson Plant. The seventh LM6000PC engine has a partial installation already, and the project will complete the VIGV system for this engine. For LM6000PC SPRINT gas turbines, which the Jackson Plant has, the VIGV upgrade is expected to yield a significant fuel efficiency improvement at part power. The average fuel efficiency improvement at 70% of maximum power is greater than 2%. The VIGV also helps minimize variable bypass valve ("VBV") flow and pressure levels, thereby reducing associated flow noise. The VIGV system improves performance for both simple cycle and heat-recovery cycles when operating at less than full load;

- GSU Transformer Site Spare ($833,333). This project provides Jackson with a reliable spare GSU to which it currently does not have access. The main transformers (GSUs) are a single point of failure to delivering power from the generators to the grid. For failure of one main transformer, lost generation would be 47 MW to 104 MW, depending on which generator(s) are connected. The lead time for a new transformer is three-to-four years, since every transformer of this size is custom built, and a large quantity of special raw materials is required. The Company's spare transformers located at Campbell, Karn, Lake winds, and Crosswinds do not have the correct voltage (138kV-13.2kV-13.2kV) or correct winding configuration (WYE-DELTA) to function at Jackson so they cannot be considered for use as spares;

- DCS Evergreen replacement ($666,667). This project replaces the GE DCS with the latest version available at the time of the project. The system is currently running on a VMware virtualized system. The system was installed in 2020. This Evergreen will only replace the existing GE Software, Operating Systems, and miscellaneous upgrades. The controller drops and rack-mounted servers will not be replaced for this upgrade. (Standard practice is to replace virtualized system hardware every eight years to reduce costs.) The DCS must be upgraded at a four-to-five-year upgrade cycle to maintain reliable control and recent operating systems and applications that are patchable. 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 (O/S) 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

- Fourteen additional projects at Jackson Plant totaling $1.098 million, with each individual project representing $225,000 or less in expenditures. These projects include (13476) JGS - LM1-6 Steam injection trap replacements, generator

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.

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

implementation began in 2021 and is planned to be completed in 2024. In 2021, the engineering was completed, and the design was approved by FERC; and

- The LPEJ Chambers enclose the penstock expansion joints in concrete chambers. The penstock expansion joints allow penstock expansion with seasonal temperature changes. The waterstop is a membrane intended to prevent groundwater from leaking into the LPEJ. Some joints have been leaking since shortly following plant construction. In February 2017, a depression was discovered upstream of Ludington Unit 3, which was caused by transport of soil into the chamber by inflowing groundwater. Historically, Consumers Energy sealed the leaks into the LPEJs using hydrophobic polyurethane grout. However, the waterstops are at the end of their expected life and grouting is no longer an effective solution. Failure to remedy the in leakage is a threat to generation because if the settlement of the chambers reaches a certain threshold, the generation unit(s) will remain in a forced outage until the LPEJ chamber(s) can be stabilized. The implementation of this project reduces current risk of a potential failure mode and supports Ludington unit generation well into the relicensing period.

The following projects are less than $1 million but are important to regulatory compliance and reliability:

- Replace Barrier Net Panels ($679,115). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Replace 480V Dike Load Centers ($993,800). 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 Oil Water Separator Replacement ($780,249). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- LPS Intake Gate and Gate House Mechanical Replacement ($409,099). This project spans the 14-month projected bridge period and the projected test year, and its basis is included in my discussion of the projected test year capital projects for Ludington;

- Governor Replacement ($474,167). 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;

- Ludington All Unit Critical Valve and Actuator Replacement ($565,000). The scope of this project is to replace valves, actuators, and associated equipment

critical to unit specific operation. There are also certain valves that provide routine tagging points that provide worker protection. Many of these valves have known issues such as damaged seals (leakage when the valve is closed), leaking packing (cannot be tightened further), and severely corroded valve stem extensions. Additionally, many of these valves are paired with pneumatic actuators which have also been identified with operational issues. Most of the handwheels are broken and do not provide a secondary means of operating the valve if the pneumatic actuator were to fail. This could present a particularly dangerous situation if a pipe were to fail. Additionally, damage to the actuator linkages and slides have been noted in previous inspections. The linkage damage has introduced play or slop into the mechanism which can be seen during operation and will lead to eventual failure of the mechanism; 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.

The LPS units are controlled by using the original hardwired electromechanical relay control system to operate the units. A modern DCS system will provide the LPS units with improved diagnostic and troubleshooting capabilities. The DCS system will make it easier to automate any updates of equipment and systems that are integrated with the unit operation, and to implement, test, and verify changes to operating criteria. Furthermore, the modern DCS has the capability to perform these functions at a lower cost and requiring less time.

The existing relay control system is based on electromechanical devices that wear and become less reliable over time. The relay contacts wear, and increased resistance can cause intermittent failures. Troubleshooting these issues are difficult and time-consuming. The relay control system will not last until end of life of the units and need to be upgraded to a modern DCS control system. The Emerson Ovation DCS infrastructure was installed as part of the 2019-2021 Data Acquisition System ("DAS"), Annunciator, PLC, and Sequence of Events recorder replacement project. This provides a common historian, HMI graphics control, alarm management system and modern control system for reliable efficient unit operation. The DAS project provides the infrastructure to build upon for full site/unit control at LPS;

- Replace 480V DLCs ($1,566,400). The scope of this project is the replacement of the 20 480V DLCs over a six-year period that began in 2020 at a capital expenditure amount of $0.671 million. The DLCs are original plant equipment and suffer from corrosion and deterioration. The primary purpose of the DLCs is to distribute power to 193 dike drain pumps and 34 pumping relief wells located around the reservoir. The purpose of the dike drain pumps is to keep the upstream face of the dike in a drained condition and to protect the asphalt liner from damage due to differential pressure. The purpose of the pumping relief wells is to keep groundwater at pre-construction levels, thereby minimizing the likelihood of a downstream slope failure. Replacement of the DLCs over a six-year period will provide high electrical system reliability and ensure FERC compliance;

- LPS Commons Station Power Transformer ("SPT") Life Cycle Management ($1,150,000). The scope of this project is to procure and replace all six SPTs with new to suit size and configuration in current LPS footprint. The SPTs are original to the site, and are in service outdoors on the LPS roof. The benefits of the project are restoration of system voltage to rated, increase site equipment life span, extension of life expectancy to that of site, enablement of the ability to perform routine maintenance without risk of damage, and reduction in the probability of failure and the associated risk of not having a spare;

- 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

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

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.

Q. What is the basis for the projected $3.096 million capital investment in the projected test year?

A. The projected $3.096 million capital investment in the projected test year will fund various projects. One of these projects is greater than $1 million, and is presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, line 20. The basis for these projects is described below:

- Fleet - Move the machine shop ($2,100,000). The scope of this project is to move the machine shop. The existing machine shop is located at the Campbell site and with the closure of the Campbell units on May 31, 2025, the Company will likely have to relocate the existing machine shop. Options for the project include (1) doing nothing and going to third parties for parts which will impact both cost and timing of delivery, (2) purchasing another machine shop, (3) section off the training center at Campbell and move the machine shop to that building, and (4) Building a machine shop in a centralized location to better service all generation sites.

  The machine shop has proven its financial viability, with a positive variance of $67,978 in 2023. It has consistently demonstrated the ability to generate revenue exceeding operational costs, a trend expected to continue based on projections. The shop's ability to quickly turn around projects and fabricate parts faster than external vendors has led to substantial savings, particularly in replacement power costs, estimated at $300k annually; and

- Eight additional projects for generation cyber security, laptop and capital business tool purchases for Generation Engineering, Electric Supply, Environmental Services, Lab Services, Business Services, and Enterprise Project Management ($996,250).

<u>COMPANY-OWNED SOLAR RESOURCES</u>

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 Company-owned solar resources.

A. The Company plans to invest $249.572 million in the 14-month projected bridge period and $275.959 million in the projected test year in Company-owned solar resources, as

shown on Exhibit A-12 (RTB-3), Schedule B-5.2, page 2, line 50, columns (h) and (j), respectively.

Q. What is the basis for the projected $249.572 million capital investment in the 14-month projected bridge period?

A. The projected $249.572 million capital investment in the 14-month projected bridge period will fund the IRP-approved solar generation development. This entire investment amount is reflected in two separate projects, Muskegon Solar and Spring Creek, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 8, lines 32 and 33. The basis for these projects is described in the direct testimony of Company witness Clark.

Q. What is the basis for the projected $275.959 million capital investment in the projected test year?

A. The projected $275.959 million capital investment in the projected test year will fund the IRP-approved solar generation development. This entire investment amount is reflected in three separate projects, Muskegon Solar, Washtenaw, and Spring Creek, which are each greater than $1 million and are presented on Exhibit A-12 (RTB-3), Schedule B-5.2, page 9, lines 39 through 41. The basis for those projects is described in the direct testimony of Company witness Clark.

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.

Q. Are you supporting any other projected capital expenditures for generation related projects in the test year ending February 28, 2026?

A. Yes. I am also supporting an IT project, Generation Operations Digital Work Management. The test year projected capital expenditure amount is $713,873, and the test year projected O&M expense amount is $54,383. These amounts are reflected in the exhibits of Company witness Shivaji Kandan. The scope of the project includes: the initial roll out for Electric Generation at Ludington, and Renewable Generation, which would include: (1) purchase of mobile field devices for Ludington, (2) purchase of additional mobile work management software licenses, (3) development and configuration of forms and workflow for these groups, and (4) enhancement of the wireless connection at Ludington.

Q. What are the benefits of this technology project?

A. This project provides the following value to the Company: (1) Productivity is improved, and human struggle reduced by simplification of work tracking through the mobile software. Time sheet charging is incorporated to the work order when someone on the crew pushes the clock to start versus being separately entered through SAP Employee Self Service. If there is more than one person on a crew, information is entered for the full crew versus individually, including time tracking. Functionality is available to more easily create a digital punch list in the field when a worker sees something instead of later writing it on a punchboard and entering it separately into SAP; (2) Employee Engagement improves as the more tech savvy candidate pool for these positions are looking for mobile software to help them do their jobs; (3) Quality is improved by creating a digital punch list when the technicians find an issue versus manually documenting it later. Accuracy increases and rework decreases when updates are performed right at the time and place of

the work instead of afterwards. Productivity can also be tracked and measured for further improvements. This level of tracking is not possible with the current process and information; (4) Safety is improved as employees have remote access to manuals to reference before moving forward with and during their work. The access to manuals increases productivity and better supports error reduction training by having the manuals available so a worker can move beyond "I think" and "I believe." The project will mitigate the risk of work and safety errors from using outdated procedures; (5) For Renewable Generation, the improved maintenance program will reduce equipment downtime resulting in an increase to Megawatt hours produced; and (6) For Ludington, the new mobile devices will allow working with electronic Systems Operations Management System ("eSOMS") which will improve productivity and reduce non-premise time.

Q. Did the Company consider alternatives for this project?

A. Yes. The alternatives considered include: (1) Utilizing an SAP work management mobile solution. An SAP work management solution is not preferred since it is a new solution and requires additional project and support cost; (2) Continuing the manual paper-based process. Continuing the manual paper-based process was not chosen because of process waste, re-work, and human error; (3) Customizing the existing electronic eSOMS mobile application to add work management functions. A custom eSOMS mobile application was not chosen because it would require additional project cost and an ongoing support budget for a custom solution that the eSOMS product was not intended to support; and (4) Utilizing an out-of-the-box solution to minimize cost and risk to the Company and its employees. The combined Service Suite and digital form solution is the preferred option because it is

a proven solution and provides the mobility and digital benefits at a lower cost than other alternatives.

GENERATION CAPITAL EXPENDITURES—SUMMARY

Q. Are the Company's capital expenditures in power generation reasonable and prudent?

A. Yes. As discussed, the proposed capital expenditures are directly aligned with the Company's generation asset strategy and, as a result, will provide economic value for power supply customers in the energy and resource adequacy markets. Other capital expenditures in generation are related to regulatory and environmental compliance, and thus are not discretionary. Company witnesses Clark and Monroe provide additional discussion in their direct testimony.

SECTION IV

GENERATION O&M EXPENSE

Q. What are the major drivers in determining the O&M expense levels you are sponsoring in this proceeding?

A. The major drivers are identifying the funding needed to support the daily operation and maintenance of the Company's fleet of generating facilities and identifying the funding needed for certain internal organizations that support Generation Operations.

Q. For purposes of your direct testimony in this case, what does the Generation O&M cost represent?

A. In addition to the Company's generation fleet, I am sponsoring the O&M expenses for the Electric Supply Operations and PSCR organization, Electric Regulation and Strategy Implementation organization, Financial Planning organization, Renewable Energy

Department, Contracts and Settlements organization, Generation Asset Management organization, Electric Sourcing and Resource Planning organization, and Enterprise Project Management and Environmental Services organization.

Q. Please describe Exhibit A-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

approved the maintenance plan, a schedule is created. The overall objective is the safe, reliable, and cost-effective generation of electricity.

Q. How are Generation O&M expenses categorized?

A. Generation O&M expenses are categorized into four primary components – "Base," "Environmental Operations," "Major Maintenance," and "Retention and Separation."

Q. What are Base O&M expenses?

A. Base O&M expenses are comprised of two categories – labor and non-labor. Labor is the primary component and typically has a predictable, stable rate of increase. Because most of the Company's generating units have been in service for years, the Company has an excellent basis upon which to make accurate forecasts. Non-labor expenses also tend to increase at a predictable rate and include items required to operate the plants. These items include but are not limited to: (1) fuel (diesel and gasoline) for equipment and vehicles; (2) material; (3) tools; (4) cleaning supplies; (5) facilities; (6) security; and (7) road and grounds maintenance.

Q. Please explain how the 2023 Actual O&M expenses were developed.

A. The 2023 Actual O&M expenses were taken from Consumers Energy's internal accounting records.

Q. Please explain how the 14-month projected bridge period and projected test year Base O&M expenses were determined.

A. Base O&M expenses for the projected bridge period ending February 28, 2025, and projected test year ending February 28, 2026 shown on Exhibit A-43 (RTB-4), page 1, line 1, columns (c) and (d), were determined by considering staffing levels and historical spending. Total O&M expense for the years 2023 through the projected test year

demonstrates average annual decreases of approximately 2.7%. As discussed later in this direct testimony, this average annual decrease reflects a change in the mix of the Company's owned generating assets as well as focused cost reductions. Exhibit A-43 (RTB-4), page 1, lines 3 and 4, identify Adjusted O&M expenses which are new or projected to change from past years' expense levels. These include items that are required by law to maintain environmental compliance, for the safety of employees, and to support the reliability of service to customers, specifically, Environmental Operations and Major Maintenance. Exhibit A-43 (RTB-4), page 1, line 5, identifies Adjusted O&M expenses which are related to Retention and Separation expenses associated with the Karn and Campbell sites. These expenses were required for the safe and reliable operation of Karn Units 1 and 2 through their May 2023 retirement and are required for the continued safe and reliable operation of Campbell Units 1, 2, and 3 through their May 2025 retirement.

Q. How do the historical and projected test year O&M expense amounts compare to prior years?

A. The 2023 historical O&M expense amount of $118.849 million and the projected test year O&M expense amount of $111.851 million compare quite favorably to the actual O&M expense amounts for 2021 and 2022. The 2021 generation O&M expense amount was $155.204 million, and the 2022 generation O&M expense amount was $150.031 million. As I previously stated, the O&M expense reductions reflect a mix of generation asset changes as well as other focused cost reductions.

Q. Please explain Exhibit A-43 (RTB-4), page 2.

A. Exhibit A-43 (RTB-4), page 2, presents the amounts of the projected O&M expenses that were developed by applying either an inflation rate or contract rate to historical O&M

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

Q. Please explain how the various inflation and contract rates were applied to Labor, Material, Contractor, and Non-Labor Other O&M expense on Exhibit A-43 (RTB-4), page 2.

A. The historical labor on line 1, column (b) reflects a combination of both Operating Maintenance and Construction ("OM&C") and non-represented labor. Inflation rates of 2.4%, 2.2%, and 2.2% were applied to labor on line 1, material on line 2, contractor on line 3, and non-labor other on line 4 to develop the annual increase amounts in columns (d), (f), and (h).

Q. Please discuss how the adjustments on Exhibit A-43 (RTB-4), page 2, column (i) were determined.

A. As previously discussed, the Company projects the future maintenance needs of each unit. The test period projected O&M expense amount of $111.851 million reflects that evaluation. Within the test period projected amount of $111.851 million, there are several adjustments that result in a projected amount that differs from the amount that is calculated based solely on inflation.

Q. Please discuss the adjustments that are reflected in the test year projected amount of $111.851 million.

A. As previously discussed, the Settlement Agreement reached in the Company's 2018 IRP reflects the retirement of Karn Units 1 and 2 on May 31, 2023 and the Settlement Agreement reached in the 2021 IRP reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025 and the addition of Covert Units 1, 2 and 3 on June 1, 2023.

Q. Please discuss the decrease in O&M expense for Karn Units 1 and 2.

A. The 2023 O&M expense for Karn reflects the fact that Karn Units 1 and 2 retired on May 31, 2023, leaving only Karn Units 3 and 4 operational. The actual O&M expense for the Karn site in 2023 was $19.091 million versus the projected O&M for the test year at $13.106 million, with the biggest decrease reflected in base O&M. The 2023 environmental operations expense for the Karn site was $2.254 million and that has been reduced to $0.093 million in the projected test year. The 2023 base O&M expense was $16.554 million whereas the projected test year base O&M drops to $10.411 million. The Karn major maintenance expense increases from $0.283 million in 2023 to $2.602 million in the projected test year. This increase reflects the fact that the Company limited the amount of major maintenance it planned for Karn Units 3 and 4 in 2023 since its 2021 IRP proposed the coincident retirement of those units with Karn Units 1 and 2. When the 2021 IRP settlement did not include Karn Units 3 and 4 retiring early, the Company needed to perform the deferred major maintenance. A complete discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the decrease in O&M expense for Campbell Units 1, 2 and 3.

A. The projected test year O&M expense for Campbell reflects the fact that the Campbell units will only operate for three months, March through May 2025. The projected test year expense for Campbell is $13.935 million, a $29.392 million reduction from the actual 2023 O&M expense of $43.327 million. The biggest reduction from the historical year to the projected test year is reflected in base O&M expense. The base O&M expense in the projected test year is $11.204 million, a $23.653 million reduction from the historical expense of $34.858 million. The 2023 environmental operations expense for Campbell was $6.421 million and that has been reduced to $2.186 million in the projected test year. The Campbell major maintenance expense decreases from $2.049 million in 2023 to only $0.545 million in the projected test year. A complete discussion of the test year major maintenance for Karn Units 3 and 4 is described later in this direct testimony.

Q. Please discuss the increase in O&M expense for Covert Units 1, 2, and 3.

A. The 2023 O&M expense for Covert reflects the fact that the Company didn't take ownership of the plant until June 1, 2023. The actual O&M expense for Covert Units 1, 2 and 3 in 2023 was $7.413 million for the period from June 1, 2023 through December 31, 2023. The projected O&M for the test year is $16.873 million, with the biggest increase reflected in major maintenance. The 2023 expense for major maintenance was $2.144 million however it is project to total $7.706 million in the test year. A complete discussion of the test year major maintenance for Covert is described later in this direct testimony. The 2023 environmental operations expense for Covert was $0.072 million and that expense is slightly lower at $0.053 million in the projected test year. The base O&M

reflects an increase from $5.196 million for the period from June 1, 2023 through December 31, 2023, to $9.114 million in the test year.

Q. Are these generation asset changes the only reasons for the reduced O&M expense?

A. No. As I previously indicated, the Company has implemented other focused cost reductions that have directly impacted both the actual 2023 O&M expense and the projected test year expense. These cost reductions are primarily represented by headcount reductions during 2023 which have reduced both capital expenditures and O&M expense.

Q. Did the Company implement any projects that exclusively impacted capital expenditures?

A. Yes. The Company has implemented an improved governance process and key performance management metrics that will allow it to improve the efficiency of its capital expenditures. While the Company will not necessarily reduce its overall capital expenditures, it does expect that it will be able to accomplish more work with the same amount of capital.

Q. Did the Company implement any generation capital projects which reduce other customer costs?

A. Yes. The Company implemented a project at Jackson for the HRSG Burner Element Isolation Valves Addition (see Exhibit A-12 (RTB-3), Schedule B-5.2, page 7, line 9) in 2023 that will reduce both O&M and PSCR expense. The project involved the addition of automated low point drain and vent on each gas manifold, the addition of isolation valves on all burner elements, and burner management system ("BMS") logic changes to control drains and vents. The benefits of the project are the mitigation of condensation in burner piping and elements which leads to ignition failure, burner tube failure, and flame

impingement which would eventually lead to burner elements replacements because of those issues. In addition, the project will increase generation production or capability due to less duct burner down time because of the ability to isolate individual duct burners rather than an entire HRSG. The increased generation production or capability is intended to result in a reduction of PSCR costs, and the improved reliability of the burner elements will result in reduced O&M expense.

ENVIRONMENTAL OPERATIONS

Q. What are Environmental Operations expenses?

A. Environmental Operations expenses consist of labor and materials supporting the operations of the Company's AQCS. As Federal and State emissions standards require cleaner air, Consumers Energy has installed AQCS to comply with these regulations. Consumers Energy deployed its full suite of AQCS devices in 2016, with 2017 being the first calendar year of operation. Now that the Company has experienced multiple calendar years of operation, the Company anticipates these expenses to remain relatively consistent going forward. However, because the cost to operate and maintain these critical pieces of equipment is directly related to the operation of the coal-fired power plants they support, yearly variances in the total Environmental Operations expense should be expected based on the operation of the coal plants in a given year.

Q. Please explain how the projected Environmental Operations expenses for the projected bridge period ending February 28, 2025 and test year ending February 28, 2026 were calculated.

A. Environmental Operations expenses are a combination of O&M costs related to the environmental equipment at the Karn and Campbell sites. The operations component is

primarily calculated using labor costs for operations and environmental waste disposal. The maintenance component is based on a combination of historical and estimated planned maintenance costs on the specific components of environmental equipment. 2023 was the seventh full year of operations of the environmental equipment at both Campbell and Karn, and the Company now has robust historical data to use in projecting these expenses. However, as reflected on Exhibit A-43 (RTB-4), page 1, line 3, columns (b) and (d), the walk from the 2023 historical expense of $9.225 million to the projected test year expense of $2.584 million reflects a cost reduction of $6.641 million despite inflationary increases. This cost reduction is a direct reflection of the retirement of Karn Units 1 and 2 on May 31, 2023 and the retirement of Campbell Units 1, 2 and 3 on May 31, 2025.

MAJOR MAINTENANCE

Q. What are Major Maintenance expenses?

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

Q. Please explain how the Major Maintenance O&M expenses for the projected bridge period ending February 28, 2025 and test year ending February 28, 2026 were determined.

A. Major Maintenance expenses are determined by tracking both the historical and future maintenance needs for each site and unit, considering operation safety, unit reliability, and

maximum customer value. Individual projects are calculated in a manner similar to capital projects, as discussed earlier in this direct testimony.

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

A. The Company projects that it will incur $31.203 million in Major Maintenance O&M expenses during the test year, as identified by Exhibit A-43 (RTB-4), page 1, line 4, column (d). Test year Major Maintenance expense by generating unit is presented on Exhibit A-43 (RTB-4), page 3, column (d).

Q. Why is Consumers Energy spending $31.203 million in Total Major Maintenance O&M expense during the projected test year ending February 28, 2026?

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

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

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

prices, unit performance, and simple timing variations can impact the cost and scheduling of Major Maintenance.

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

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

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

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

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

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

Q. What are the categories of Major Maintenance?

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

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

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

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

A. Boiler inspections assess the fire (outside) and steam (inside) sides of boiler tubing for weaknesses that will ultimately result in water/steam leaks. After the boiler has been properly opened, ventilated, and cleaned, scaffolding is constructed inside the boiler to provide access to the boiler tubes. Inspections are completed using a number of different methods – visual, non-destructive, and destructive. Visual and non-destructive testing are the most common methods of inspection. Non-destructive testing incorporates the use of

ultrasonic, x-ray, magnetic particle, or like technologies to measure pipe wall thickness. Boiler tubes that are in poor condition or exceed minimum wall thickness are repaired or replaced. After all repairs are complete, boiler tubes are pressure tested. Each boiler is inspected on a specific time schedule, with a one-, two-, or three-year maximum interval. Internal components with known problems are inspected more frequently. External inspections are performed daily by Generation Operations and annually by state inspectors.

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

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

Q. Please define non-outage maintenance.

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

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

Q. Please describe Campbell 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 1, column (d), Campbell Units 1 and 2 Major Maintenance expense is forecasted to be $0.268 million in the projected test year ending February 28, 2026, and includes:

- 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.

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

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;

- 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,

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.

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:

- 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

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

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;

- 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

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

$15.847 million for Campbell. The 14-month projected bridge period expense of $11.158 million is entirely based upon expense of $11.158 million for Campbell. The projected test year expense of $4.621 million is based upon expense of $4.621 million for Campbell.

Q. Is the Company requesting O&M recovery of the $4.621 million projected amount for the projected test year?

A. No. The Company is not requesting approval of this projected amount in Generation O&M expense. The Company received approval in electric rate case, Case No. U-20697, to defer the recovery of the Karn Retention and Separation O&M amounts for 2021 through 2023. The Company received approval to defer the recovery of the Campbell retention and separation amounts in the Settlement Agreement in its 2021 IRP. As such, the projected amounts for 2023 through the projected test year ending February 28, 2026 are not included in the Total O&M amounts on Exhibit A-43 (RTB-4), page 1, line 6, columns (b), (c) and (d). Company witness Aponte supports regulatory asset treatment of these expenses in her direct testimony.

Q. Please describe the Karn retention and separation plan.

A. The Karn retention and separation plan is a people strategy that the Company has implemented to ensure that it could retain the necessary qualified employees to operate Karn Units 1 and 2 through their retirement date in May 2023, as well as during the cold and dark time period following retirement. The cold and dark condition refers to the period following plant retirement and prior to plant decommissioning. During this period, limited environmental remediation and perhaps partial demolition is performed. The facility may be physically secured with fencing and other measures to prevent vandalism or theft so as

to limit liability risks. On June 7, 2019, the MPSC approved the Company's 2018 IRP Settlement Agreement, which included the retirement of Karn Units 1 and 2 in May 2023. The Company's IRP included detailed support of the Company's need to implement a retention and separation plan to ensure that it could operate the plants safely and reliably through their retirement date.

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

A. The Company had a strong interest in keeping qualified employees working at Karn Units 1 and 2 through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. The Company's ability to hire new employees at Karn Units 1 and 2 became increasingly difficult given the short remaining lifespan of the units and, to the extent that the Company had the ability to hire new employees, the training time necessary for any new hires provided a significant challenge to operating the units both safely and reliably. The retention component utilized the best practices that the Company employed in retiring the Classic 7.

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

A. Now that Karn Units 1 and 2 are retired, the Company is following the terms of the collective bargaining agreement for OM&C employees represented by the Utility Workers Union of America ("UWUA"), and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers varies based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or

non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

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

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

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

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

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

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

Employees received their final retention incentive equal to 60% of their base pay following plant retirement if the employee was still at Karn. The payment was intended to incentivize employees to stay until the plant goes cold and dark and compensate employees for the service they rendered for the eight months (November 2022 through June 2023) prior to the payment.

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

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

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

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able

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

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

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

Q. Please describe the Campbell retention plan.

A. The Campbell retention plan is a people strategy that the Company has proposed in its 2021 IRP. As previously discussed, the Company's 2021 IRP PCA reflects the retirement of Campbell Units 1, 2, and 3 on May 31, 2025. This retention plan was proposed in order to

retain employees through the closure of the three Campbell units. This strategy is necessary to ensure that the Company can operate the Campbell units safely and reliably through their retirement date. This incentive program is the same program that is currently in place for employees at the Karn site.

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

A. For similar reasons described in the Karn retention plan, the Company has a strong interest in keeping qualified employees working at the Campbell site through their retirement date to ensure safe and reliable operations. The retention component will allow the Company to retain employees that may seek employment at other Company locations or outside of the Company. Similar to the situation at the Karn site, it will be increasingly difficult to hire new employees at the Campbell site given the short remaining lifespan of the units and, to the extent that the Company has the ability to hire new employees, the training time necessary for any new hires will provide a significant challenge to operating the three units both safely and reliably.

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

A. When the Campbell units are retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement within the Company within 60 miles from their current location, they will

be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position as well as relocation expenses if they accept a position more than 60 miles away from their current location.

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

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

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

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

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

Employees receive a periodic incentive which graduates from 20% to 30% of their base pay for service each November in years 2022, 2023, and 2024, for staying at Campbell

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

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

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

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

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

A. The Company is proud of the fact that following the retirement of the Classic 7 in 2016, all Company employees that desired to continue employment with the Company were able to do so. However, the Company is also aware of the fact that it has fewer Company locations (seven within 60 miles of the Campbell site) to which employees can relocate,

than it did in 2016. In addition, the Company will also have retired at least two of the Karn generating units in 2023, thereby further reducing the available positions. As such, the Company has anticipated the need to make severance payments to those employees that cannot find placement. As I previously stated, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA, and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees, as previously discussed for the Karn retention and separation plan.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment HH

DOE, Special Environmental Analysis (2006)

DOE/SEA-04

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/documentspub.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.

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 (SO_2), nitrogen dioxide (NO_2), lead, carbon monoxide (CO), ozone, particulate matter less than or equal to 10 μm in aerodynamic diameter (PM_{10}), 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 SO_2 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.

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.

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").

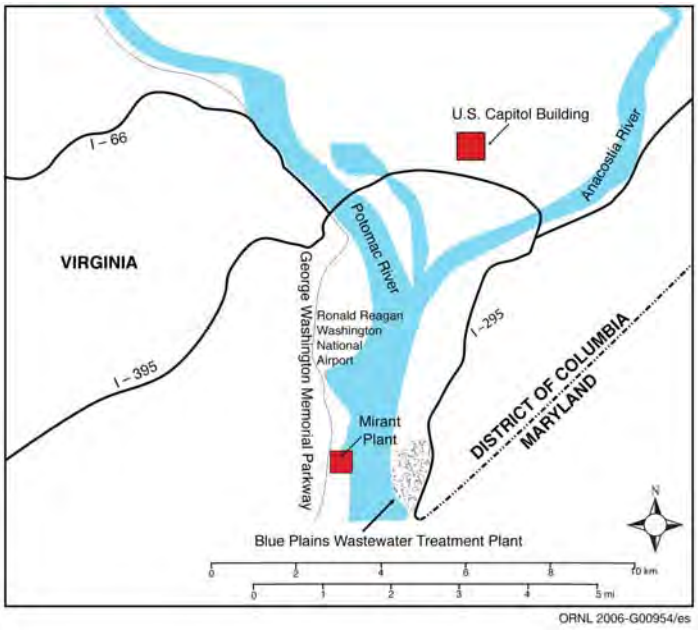

Figure S-1. The location of the Plant in relation to the central Washington, D.C. area.

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 μm 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.

[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 SO_2, 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 SO_2, PM_{10}, and NO_x emissions and to optimize use of trona to minimize SO_2 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 SO_2 and PM_{10} NAAQS. The ACO also requires Mirant to maintain alarms that alert the Plant operators if monitored average concentrations reach 80% of the standards for SO_2, including the annual SO_2 standard. In addition, the ACO requires Mirant to install and operate six new SO_2 ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO_2 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 SO_2 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 SO_2 and PM_{10} 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 SO_2 and PM_{10} because the original downwash study that prompted the shutdown of the Plant emphasized SO_2, PM_{10}, and NO_x (and the amended judicial consent decree between EPA and Mirant [EPA 2006g] deals with NO_x.) In modeling concentrations of SO_2 and PM_{10}, 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 SO_2 and PM_{10} 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 PM_{10} 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 SO_2 and PM_{10} 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 SO_2 concentrations in the normal course of business (i.e., no line outage). DOE did not simulate predictive modeling for the 3-hour SO_2 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 SO_2 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 SO_2 concentrations and adjust operation of the Plant to meet SO_2 standards for all averaging periods, actual exceedances of the annual standard are not expected to occur.

Preliminary data from the six new SO_2 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 SO_2 concentration for the monitors ranged from 4 to 63 $\mu g/m^3$, whereas Mirant's follow-up modeling gave maximum daily-average SO_2 concentrations from 25 to 570 $\mu g/m^3$. Thus, monitored concentrations of SO_2 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]
AIR QUALITY				
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 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.	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.

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 $\mu g/m^3$) and are slightly below the current NAAQS annual limit (15 $\mu g/m^3$), but exceed the NAAQS limit for the 24-hour averaging period (35 $\mu g/m^3$) 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 affect 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 affect 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 $\mu g/m^3$ for 24-hr 5.7 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 9.2 $\mu g/m^3$ for 24-hr 2.0 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 25 $\mu g/m^3$ for 24-hr 2.4 $\mu g/m^3$ for annual	Plant contributions to ground-level $PM_{2.5}$: 23 $\mu g/m^3$ for 24-hr 4.0 $\mu g/m^3$ for annual
	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 76 $\mu g/m^3$ for 24-hr 7.8 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 4.8 $\mu g/m^3$ for 24-hr 1.0 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 41 $\mu g/m^3$ for 24-hr 3.9 $\mu g/m^3$ for annual	Plant contributions to $PM_{2.5}$ at the top of Marina Towers: 43 $\mu g/m^3$ for 24-hr 5.7 $\mu g/m^3$ 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
	Negligible impacts to water quality in nearby watersheds, because these watersheds are well buffered against acid rain.			
Effects of changes in Plant water use and releases	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 (no use of trona).	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 PM_{10} 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)
µm	micrometers (i.e., millionths of a meter)
ACO	Administrative Compliance Order
Btu	British thermal unit
C	Celsius
CAA	Clean Air Act
CEQ	Council on Environmental Quality
CFR	*Code of Federal Regulations*
cm	centimeter
CO	carbon monoxide
CO_2	carbon dioxide
CT	census tract
D.C.	District of Columbia
DCPSC	District of Columbia Public Service Commission
DOE	U.S. Department of Energy
EPA	U.S. Environmental Protection Agency
ESA	Endangered Species Act
F	Fahrenheit
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FPA	Federal Power Act
FR	*Federal Register*
ft	feet
ft^2	square feet
FWS	U.S. Fish and Wildlife Service
gal	gallons
ha	hectare
hr	hour
kg	kilogram
km	kilometer
km^2	square kilometer
kV	kilovolt
L	liter
lb	pound(s)
LLC	Limited Liability Company
LOS	level-of-service
m	meter
m^2	square meter
m^3	cubic meter
MBtu	million British thermal units
MES	Model Evaluation Study
mg	milligrams (i.e., thousandths of a gram)
mi	mile
mi^2	square mile
min	minute
MSL	mean sea level
MW	megawatts
MWh	megawatt-hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NMFS	National Marine Fisheries Service
NO_2	nitrogen dioxide
NO_x	oxides of nitrogen
NPDES	National Pollutant Discharge Elimination System
O_3	ozone
Pb	lead
Pepco	Potomac Electric Power Company
PJM	PJM Interconnection, LLC
Plant	Mirant's Potomac River Generating Station (in Alexandria, Virginia)
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to 2.5 µm
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to 10 µm
ppb	parts per billion
ppm	parts per million
RCRA	Resource Conservation and Recovery Act
ROD	*Record of Decision*
SEA	special environmental analysis
SIP	state implementation plan
SO_2	sulfur dioxide
TCLP	Toxicity Characteristic Leaching Procedure
U.S.	United States
U.S.C.	United States Code
VDEQ	Virginia Department of Environmental Quality
yd^3	cubic yard
yr	year

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):

$1 \times 10^{4}_{2}$	=	10,000
1×10^{0}	=	100
1×10^{-2}	=	1
1×10^{-3}	=	0.01
1×10	=	0.001

Metric Conversions Used in this Document:

Multiply	By	To Obtain
	Length	
inch (in.)	2.54	centimeters (cm)
feet (ft)	0.30	meters (m)
yards (yd)	0.91	meters (m)
miles (mi)	1.61	kilometers (km)
	Area	
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)
	Volume	
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)
	Weight	
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 downwash[2] 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 (SO_2), oxides of nitrogen (NO_x), and particulate matter with an aerodynamic diameter less than or equal to 10 µm (PM_{10}).

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 coal[3], alone or in combination, to control SO_2 emissions in order to determine if such changes would allow simultaneous operation of more than one unit without causing NAAQS exceedances.

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[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 [SO_2], although the 3-hour and annual NAAQS for SO_2 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 SO_2 and PM_{10}, 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 SO_2, including the annual SO_2 standard. In addition, the ACO requires Mirant to install and operate six new SO_2 ambient monitoring stations in the vicinity where elevated pollutant concentrations have been predicted and to conduct actual monitoring of ambient SO_2 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 PM_{10}, NO_x and SO_2 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 SO_2 emissions." Further, the ACO requires that Mirant achieve "80% reduction of SO_2 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; ***Pre-shutdown mode for this SEA***
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; ***Pre-Order mode for this SEA***
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 *Federal Register* 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 *Federal Register* 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 SO_2 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.

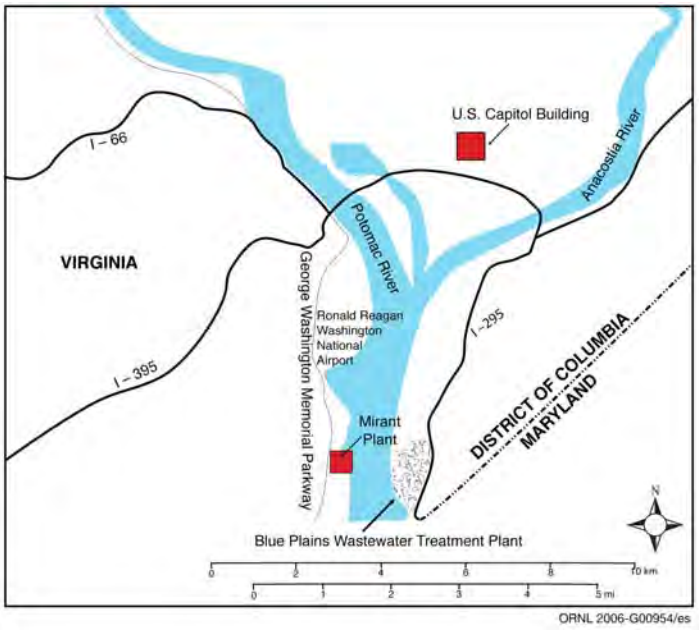

Figure 2-1. The location of the Plant in relation to the central Washington, D.C. area.

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.

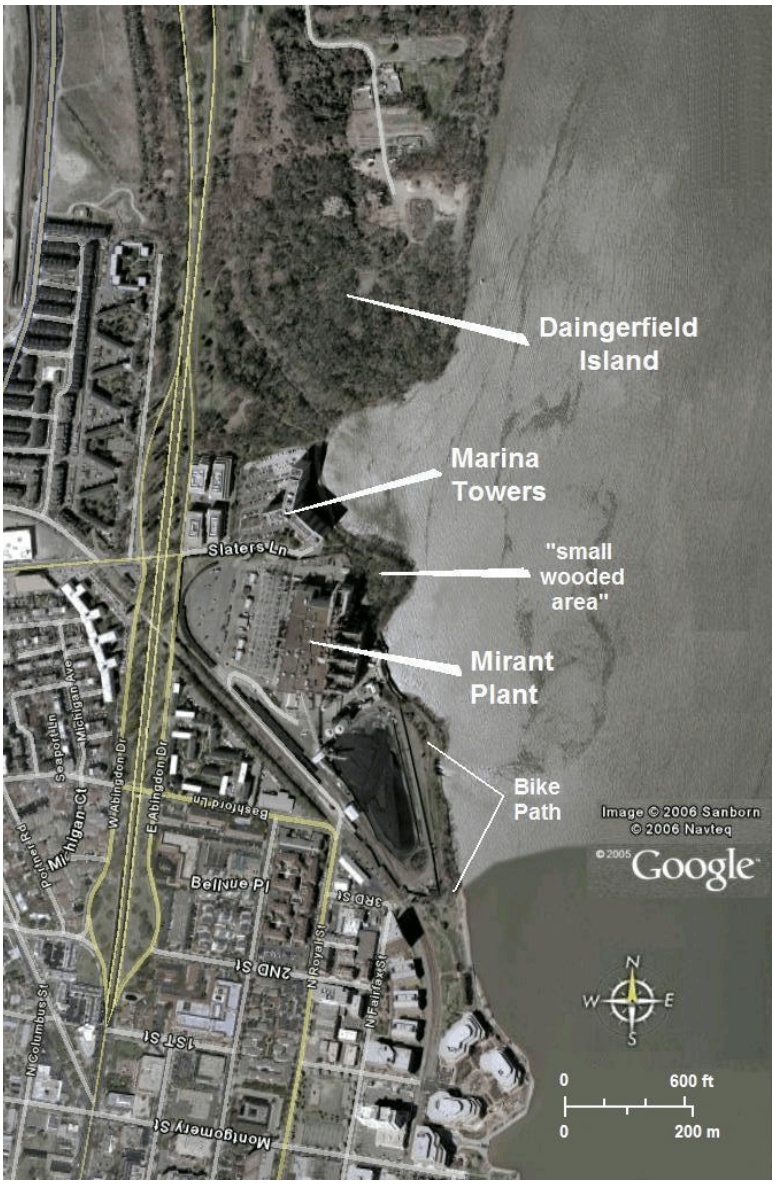

Figure 2-2. Aerial photo showing the Plant and surrounding residences.

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

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 SO_2 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 SO_2 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.

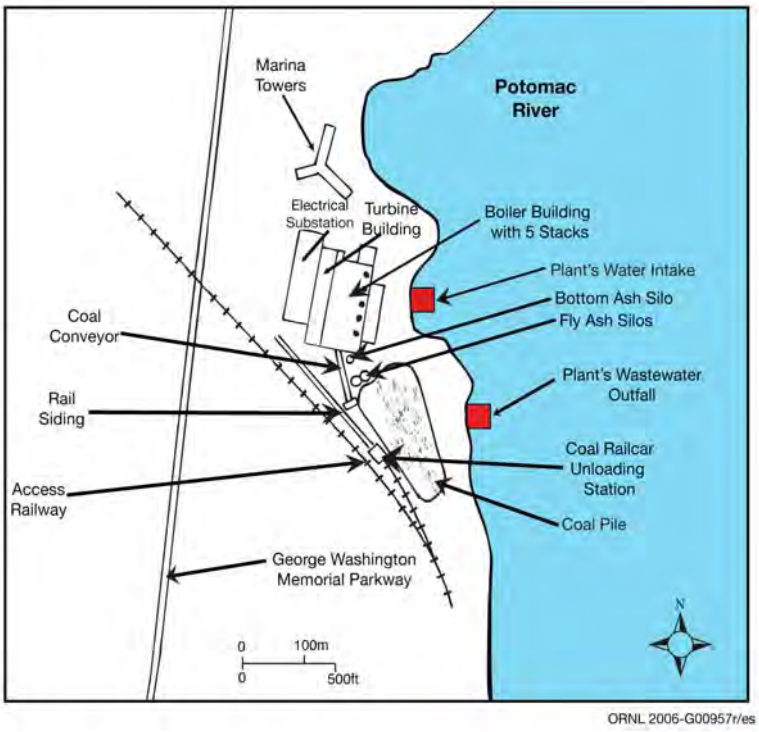

Figure 2.1-1. The site layout of Mirant's Potomac River Generating Station.

The Plant has a once-through cooling water system. Raw water is pumped from the Potomac River through a 1,250-ft^2 (116-m^2) 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 m^3/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

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 SO_2 removal. Theoretical calculations show that if trona reacted completely with SO_2 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 SO_2 (e.g., 2.345 lb trona per lb of SO_2). However, testing by Mirant found that much larger quantities of trona must be used in order to achieve desired SO_2 removal rates. Addition of trona to the exhaust gas stream at five times the theoretically calculated rate was found to remove 80% of the SO_2 (Mirant 2006c). For typical coal burned at the Plant, removal of 80% of SO_2 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% SO_2 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 m^3/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 NO_2) 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 SO_2 during its effective period of January 1, 2003, through December 31, 2007. SO_2 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 SO_2 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 CO_2.

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 m^3/day), of which all but about 0.4 million gal/day (1,500 m^3/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.

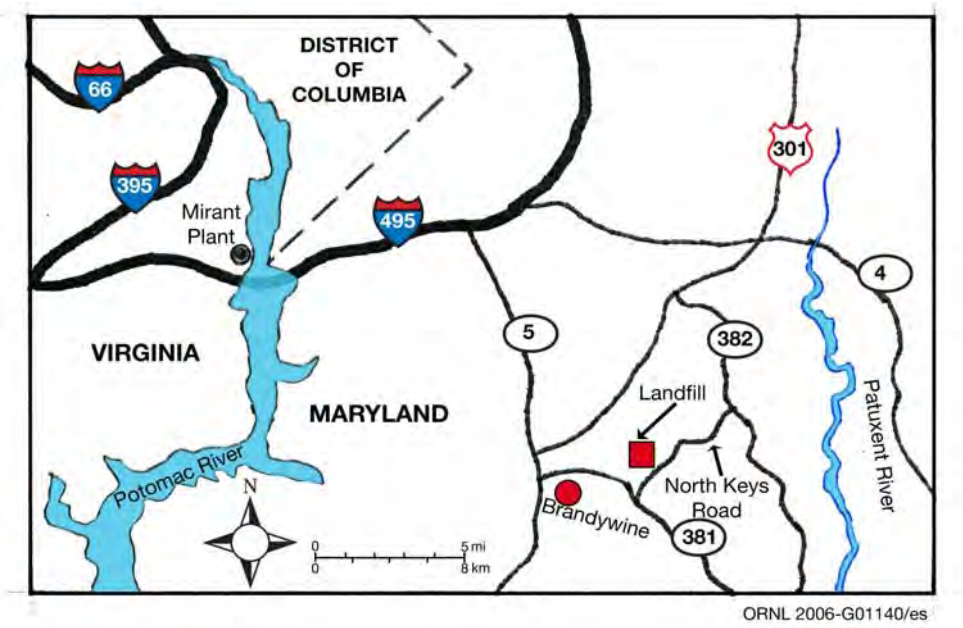

Figure 2.4-1. The location of and access routes to the Brandywine Fly Ash Facility used for disposal of solid wastes from the Plant.
Note: Mataponi Creek (not shown on the map) originates near Brandywine and flows east-northeast to the Patuxent River.

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-mi^2 (93-km^2) 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-mi^2 (93-km^2) 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.

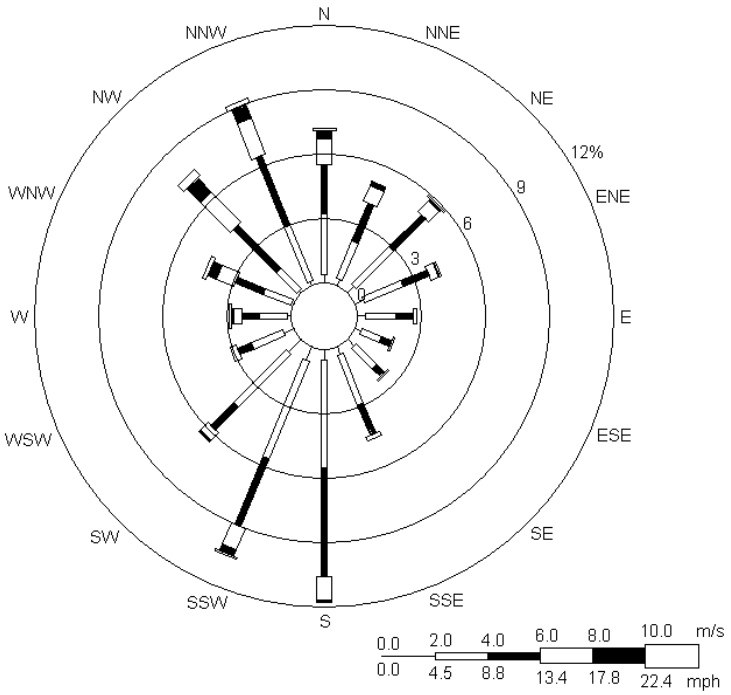

Figure 3.1-1. Wind rose for Ronald Reagan Washington National Airport, 2000-2004 weather data

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 (NO_2), ozone (O_3), particulate matter less than or equal to 10 µm in aerodynamic diameter (designated PM_{10}), particulate matter less than or equal to 2.5 µm in aerodynamic diameter (designated $PM_{2.5}$), and sulfur dioxide (SO_2).

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	4th 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
	98th 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 O_3 concentration is less than or equal to 0.08 ppm.

[c] The annual PM_{10} standard is attained when the expected annual arithmetic mean concentration is less than or equal to 50 µ/m^3 (3-year average); the 24-hour standard is attained when the expected number of days above 150 µ/m^3 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 PM_{10} 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/m^3, 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/m^3. Under new standards published on October 17, 2006, and effective December 18, 2006 (EPA 2006j), the 24-hour standard will be 35 µg/m^3. 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, SO_2, NO_2, and O_3. 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 PM_{10} 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 O_3 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]	4th 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
	98th 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)
	2nd highest 24-hour average	0.021 ppm	0.14 ppm (365 µg/m^3)
	2nd 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 PM_{10} 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, SO_2, 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 SO_2 in the U.S. is about 1 $\mu g/m^3$, the NAAQS for annual-average SO_2 concentration is 80 $\mu g/m^3$. However, human health effects have been reported for concentrations below NAAQS levels for both PM and SO_2 (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.)

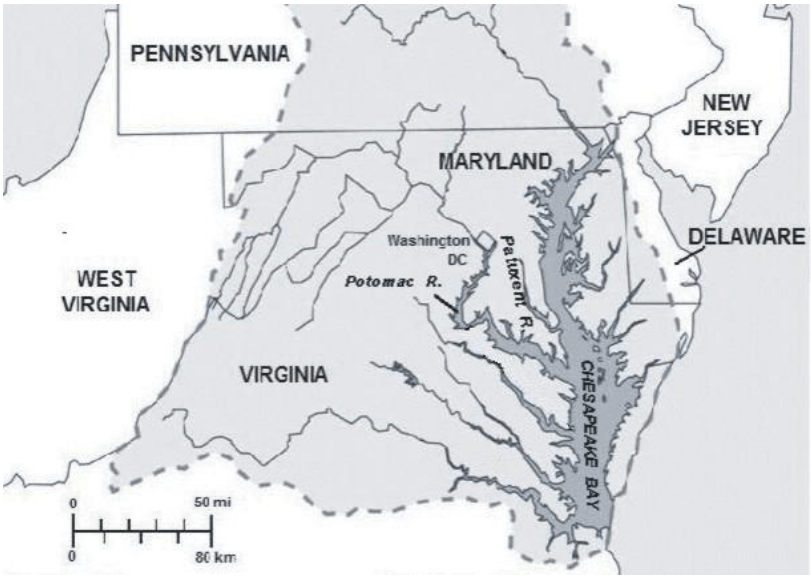

Figure 3.3-1. The Chesapeake Bay watershed includes the Patuxent and Potomac rivers.

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-mi^2 (38,000-km^2) watershed in Maryland, Virginia, West Virginia, Pennsylvania, and the District of Columbia

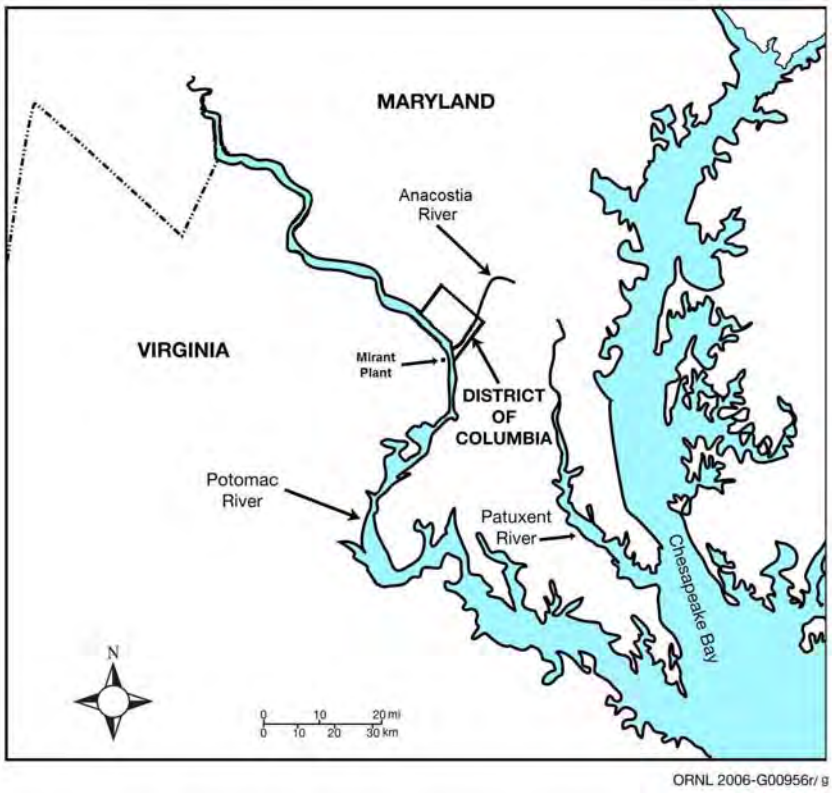

Figure 3.3-2. The Chesapeake Bay watershed near the Plant includes the Potomac, Patuxent, and Anacostia rivers.

(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 ft^3/sec (7.4 billion gal/day or 28 million m^3/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 ft^3/sec (2.7 billion gal/day or 10 million m^3/day). The long-term mean 7-day, 10-year low flow at the fall line is 628 ft^3/sec (406 million gal/day or 1.54 million m^3/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 mi^2 (456 km^2) 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 ft^3/sec (89 million gal/day or 338,000 m^3/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 mi^2 (155 km^2); the tidal portion is mainly within D.C.

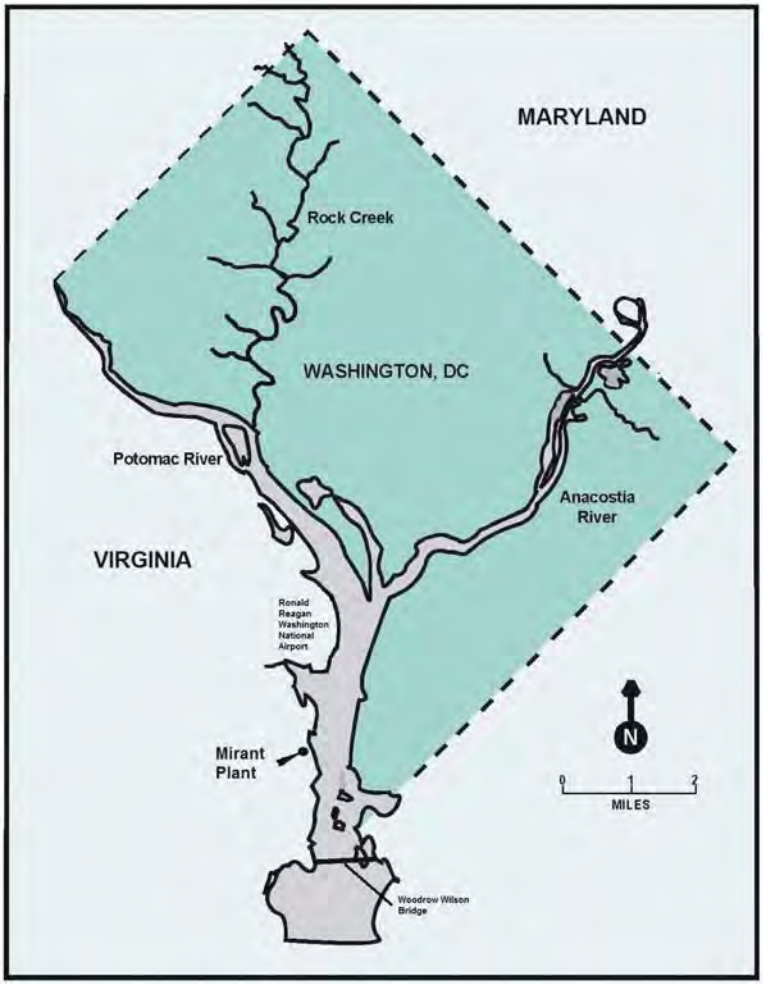

Figure 3.3-3. Location of features mentioned in the text.

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-mi^2 (220-km^2) 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 mi^2 (127 km^2) (Hagy and Kemp 2002). Total stream flow to the Patuxent estuary averages about 728 ft^3/sec (470 million gal/day or 1.78 million m^3/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 mi^2 (11,000 km^2) (including the estuarine reaches of its major tributaries) and a watershed of about 63,000 mi^2 (164,000 km^2), including the District

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 m^3/day) and a peak wet-weather capacity of 1.076 billion gal/day (4.1 million m^3/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 mi^2 (1,650 km^2) 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.

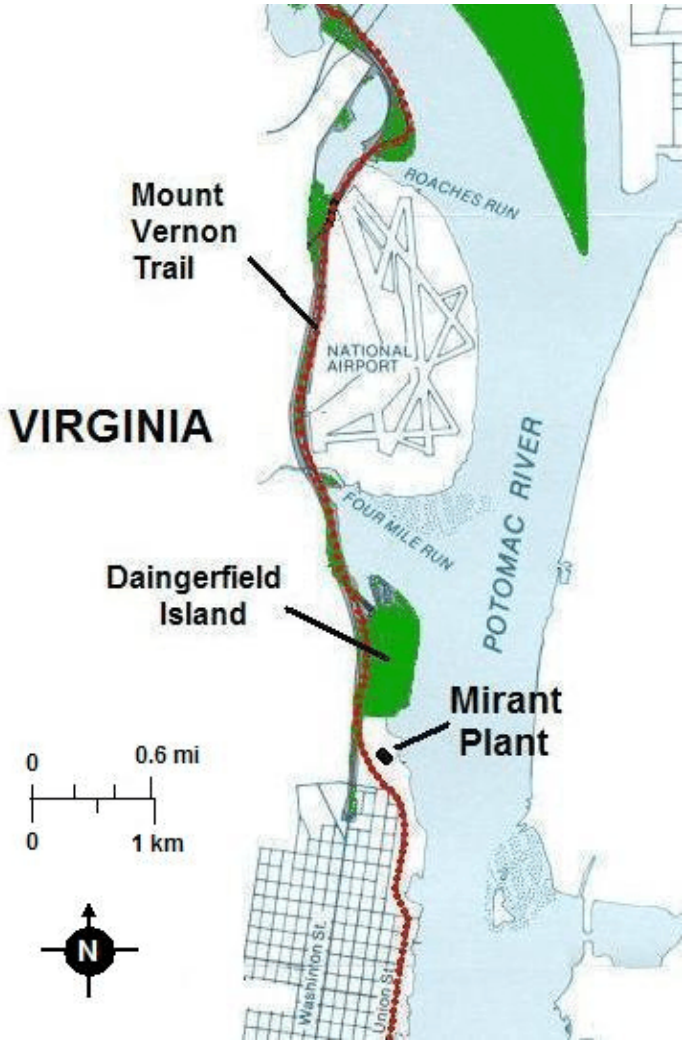

Figure 3.4-1. Location of National Park Service trail that passes the Plant.

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

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 ft^2 (140 m^2) 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 (*Corbicua 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 concern[5] 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 yd^3 (1.58 million m^3), 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).

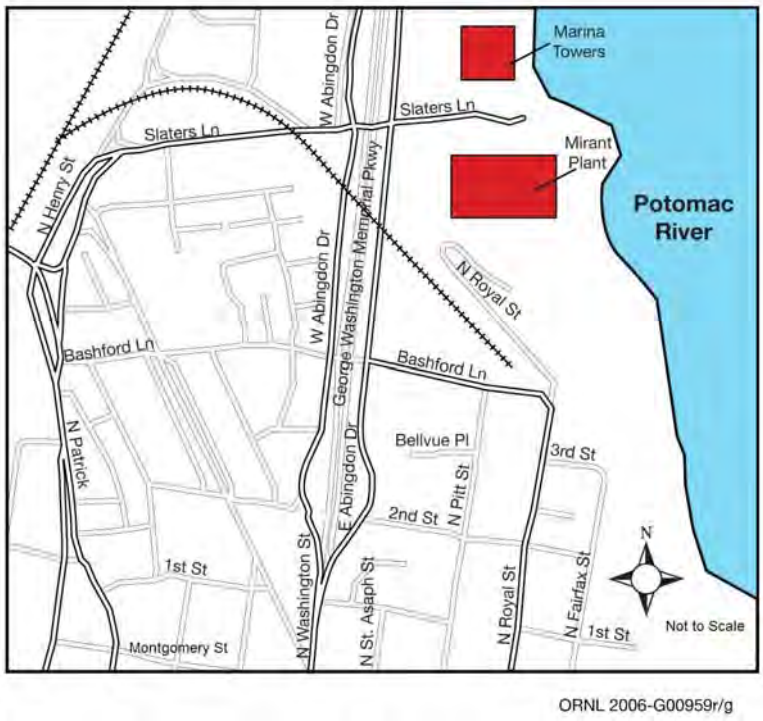

Figure 3.6-1. Access routes near the Mirant Plant.

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 traffic[6] 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)	***F***	C
Maryland 381/U.S. 301 (signalized)	***F***	***F***
Maryland 381/Baden Westwood Road (unsignalized)	***F***	B
Maryland 381/Croom Road (unsignalized)	***F***	***F***
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 tract[8] (CT) 2018.01, in which the Plant is located (Figure 3.7-1), and the four block groups[9] 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).

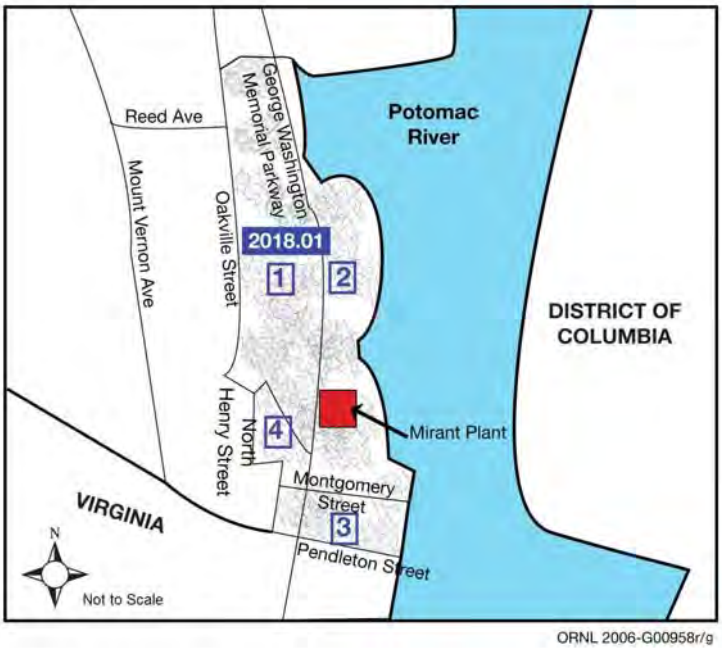

Figure 3.7-1. Block Groups 1-4 within Census Tract 2018.01.

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.

[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 SO_2 monitors[11] 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 Default[12]. 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 SO_2 and PM_{10} 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 PM_{10} when Mirant operates four or five units. Mirant is required to assume a PM_{10} emission rate of 0.055 lb/MBtu and to adjust operations to prevent a modeled exceedance for PM_{10}.

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 SO_2 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 SO_2 measured at the monitors. The ACO uses this alarm system to monitor the Plant's compliance with the annual SO_2 NAAQS limit. The

[11] Until June 20, 2006, when three newly installed SO_2 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 SO_2 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 SO_2 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 SO_2 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 PM_{10}, NO_x and SO_2 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 SO_2 emissions." Further, the ACO requires that Mirant achieve "80% reduction of SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 at a rate of 1.05 lb/MBtu and that it emitted NO_2 at a rate of 0.35 lb/MBtu for Units 1 and 2 and 0.26 lb/MBtu for Units 3, 4, and 5.

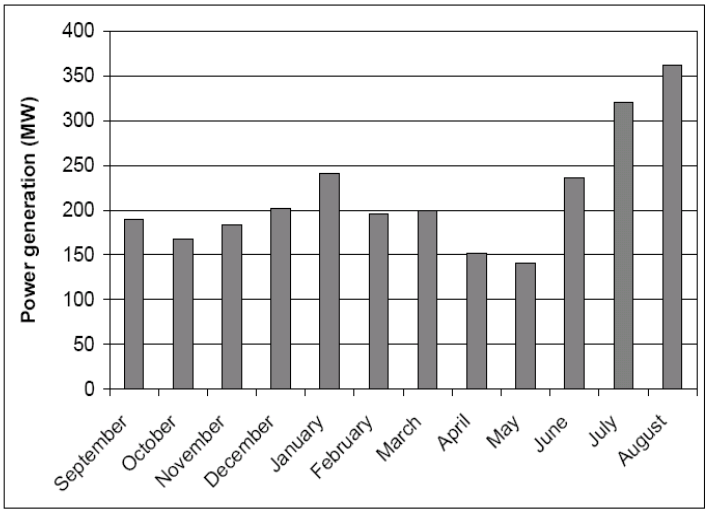

Figure 4.2-1. Monthly average power generation for September 2004 through August 2005.

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 SO_2 and about 4,300 lb (1,900 kg) of NO_x per day. SO_2 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 CO_2.

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 m^3) 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 CO_2, opacity), pounds of NO_2 released per million Btu, pounds per hour of NO_2 released, pounds of SO_2 released per million Btu, and pounds per hour of SO_2 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.

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[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 SO_2 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 SO_2 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 SO_2 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 SO_2 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 SO_2 and particulate matter. Modeled concentrations of SO_2 and PM_{10} 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

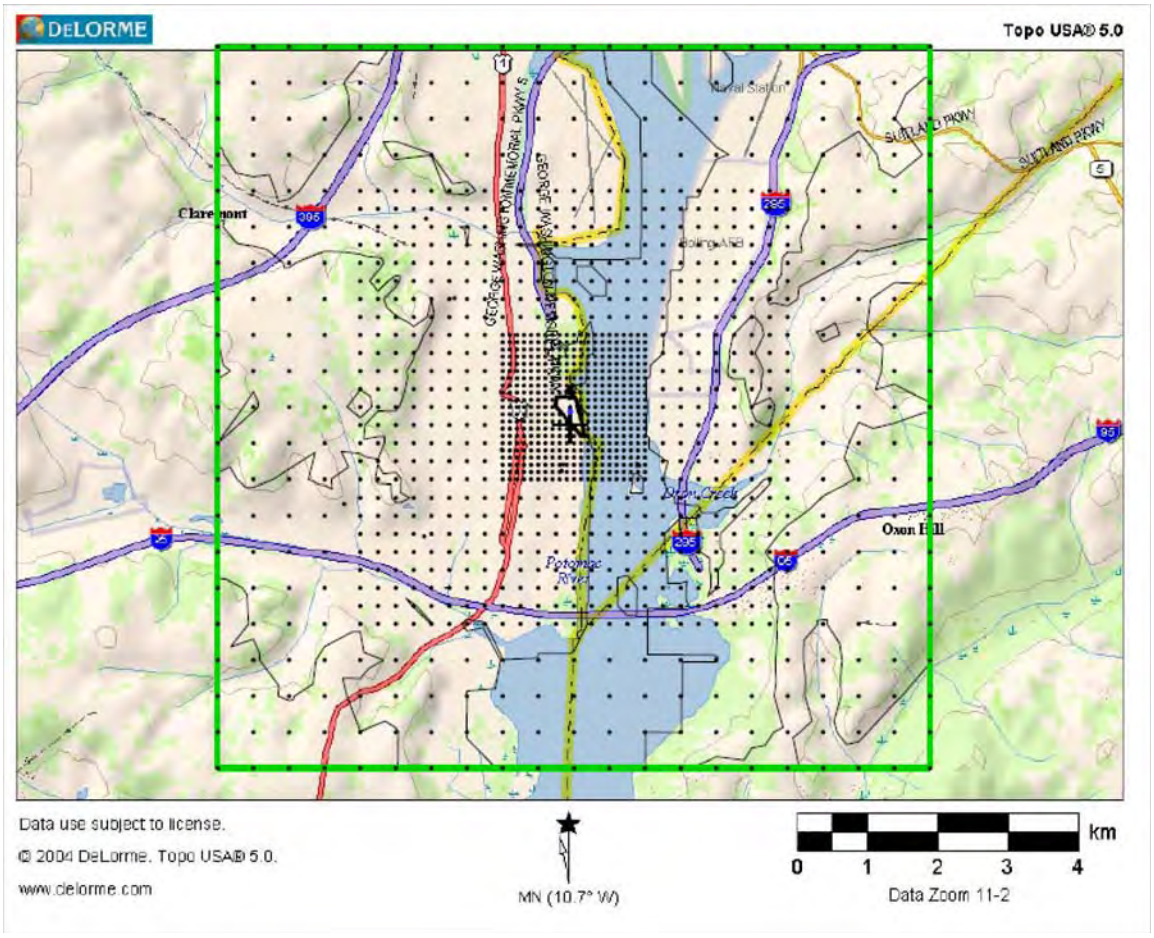

Figure 4.3.1-1. Map of receptor grid points for atmospheric dispersion modeling.

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 SO_2 emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO_2 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 SO_2 emission rates) that modeling by Mirant's contractor had demonstrated would not lead to exceedances of the 24-hour average SO_2 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 2005[17] and that at all times Mirant injected enough trona to achieve 50% SO_2 removal (i.e., controlled to 0.525 lb/MBtu). DOE estimated 50% SO_2 removal to be an average or typical removal rate. At low power generation times and/or favorable wind conditions, very little SO_2 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 SO_2) 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 SO_2 limits occur during line outage periods. Although removal of 80% of SO_2 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 SO_2 from stack gases. DOE has not modeled 80% removal because Mirant does not stockpile sufficient trona to maintain 80% SO_2 removal for an extended (typically, two-week) line outage.

Sulfur Dioxide. The SO_2 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 SO_2 NAAQS limit.[19] DOE performed this procedure for every modeled day (except

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[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 SO_2 limit was based on a concentration of 314 $\mu g/m^3$ (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 SO_2 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 PM_{10} per MBtu when trona injection was employed and 0.035 lb/MBtu PM_{10} 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 PM_{10} emission rate. For all other periods after the Order, DOE assumed the 0.019 lb/MBtu emission rate. DOE modeled stack emitted PM_{10} emissions using the same operational schedule as used for SO_2 modeling. However, DOE did not simulate the effects of daily predictive modeling on PM_{10} emissions because DOE found that with the 0.019 lb/MBtu emission rate, stack emissions never lead to exceedances of the NAAQS limit for PM_{10}.

DOE modeled fugitive PM_{10} 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 SO_2 emissions by 50%. The Plant may operate with less than 50% SO_2 removal when

[19] (...continued)
of 365 less the assumed background concentration of 51 µg/m^3).

modeling (based on predicted weather conditions) does not indicate an exceedance would result. Conversely, the Plant may remove more than 50% of SO_2 or reduce power generation rates when modeling indicates this is necessary to avoid exceedances of the NAAQS. The assumption of 50% SO_2 removal is likely to mean that DOE's modeling underestimates the period-average concentrations of SO_2. However, because of the way DOE has modeled daily predictive modeling, this should introduce little error in estimates of maximum short-term SO_2 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 SO_2 emissions by that percentage.) While it is mathematically possible to exactly meet the 314-µg/m^3 24-hour limit, DOE expects Mirant to keep SO_2 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% SO_2 removal during line outage situations unless predictive modeling demonstrates that this level of SO_2 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% SO_2 removal during line outage situations.

5. DOE has used an estimate of fugitive PM_{10} 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 SO_2 NAAQS. The ACO requires

[20] Although not required, Mirant is known to be targeting 200 µg/m^3 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 SO_2 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 SO_2. 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 SO_2 concentrations occur at the rooftop at Marina Towers. Initial monitoring data collected by SO_2 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 SO_2 and PM_{10} 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 SO_2 and PM_{10} 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 SO_2 emissions. Table 4.3.1-1 shows that modeling of pre-shutdown operations predicts significant exceedances of the NAAQS for SO_2 concentrations. The table also shows exceedance for the maximum 24-hour PM_{10} concentration. The maximum PM_{10} values reported here are dominated by fugitive dust emissions. Maximum modeled concentrations of PM_{10} 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 SO_2 limit would occur under 8-8-8 operation even if no SO_2 control were employed. Consequently, during this period Mirant did not control SO_2 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 SO_2 limits.

During 2005 and 2006, Mirant implemented several fugitive dust control measures (Section 2.5). Modeling of PM_{10} 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 PM_{10} concentrations for pre-Order operations are substantially lower than for pre-shutdown operations and meet the PM_{10} limits.

Table 4.3.1-1. Modeled maximum ambient SO_2 and PM_{10} concentrations (µg/m^3) for Plant operations among all receptor locations.

	SO_2			PM_{10}	
Operating Scenario and Period	**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 SO_2 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 PM_{10} 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 PM_{10} 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 SO_2 and PM_{10} emissions for these two time periods.

December 20, 2005, through June 30, 2006. For the December through June period, maximum modeled SO_2 concentrations (Table 4.3.1-1) show exceedances of the SO_2 limits during the January line outages, when the highest modeled 3- and 24-hour SO_2 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 PM_{10} during either line outage or non-line outage periods. The fugitive dust parameters used in modeling PM_{10} 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 SO_2 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 SO_2 limits. DOE's modeling assumed that the Plant would scale back operations to meet the 24-hour SO_2 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 SO_2 limit.

The modeled exceedance of the longer-period average SO_2 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 SO_2 limit. Operating close to the 24-hour limit (314 g/m^3) 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 SO_2 concentrations near the top of Marina Towers (where the maximum modeled exceedances occur) for close approaches to NAAQS SO_2 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 SO_2 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 PM_{10}.

Operations during a potential extension of the Order until new transmission lines are installed. Table 4.3.1-2 presents modeled maximum concentrations of SO_2 and PM_{10} 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 SO_2 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 SO_2 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 SO_2 NAAQS averaging periods. Consequently, DOE anticipates that actual exceedances of the SO_2 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 PM_{10}.

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 SO_2 data

Pursuant to the requirements for performing the MES (Appendix B, Section VI), Mirant has installed six SO_2 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 SO_2 and PM_{10} concentrations (µg/m^3) for Plant operations among all receptor locations for a potential extension of the Order.

	SO_2			PM_{10}	
Operating Scenario and Period	**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 SO_2 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 PM_{10} 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 PM_{10} 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/m^3. 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/m^3. 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 SO_2 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/m^3 and a 98th-percentile 24-hour average concentration of 65 µg/m^3. 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/m^3 for the annual average and institute a 35 µg/m^3 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/m^3; the 98th-percentile 24-hour average concentration was 35.7 µg/m^3.[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 PM_{10} 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 PM_{10}. Based on this guidance, DOE assumed that 15% of fugitive PM_{10} was $PM_{2.5}$. The AP-42 factors for the $PM_{2.5}$ fraction of PM_{10} 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 PM_{10} 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 SO_2 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 $\mu g/m^3$ (38 $\mu g/m^3$ due to Plant operations alone; that is, without background) at ground level and 112 $\mu g/m^3$ (76 $\mu g/m^3$ due to Plant operations) at the top of Marina Towers. The annual average ground level $PM_{2.5}$ concentration was estimated to be 20 $\mu g/m^3$ (5.7 $\mu g/m^3$ due to Plant operations), and the average annual $PM_{2.5}$ concentration at the top of Marina Towers was estimated to be 22 $\mu g/m^3$ (7.8 $\mu g/m^3$ 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 $\mu g/m^3$ (9.2 $\mu g/m^3$ 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 $\mu g/m^3$ (4.8 $\mu g/m^3$ due to Plant operations). The maximum estimated ground-level annual average $PM_{2.5}$ concentration would have been 16 $\mu g/m^3$ (2.0 $\mu g/m^3$ due to Plant operations), and the maximum annual average concentration at the top of Marina Towers would have been 15 $\mu g/m^3$ (1.0 $\mu g/m^3$ due to Plant operations).

Operations under the Order. For the duration of the Order, the estimated maximum 24-hour-average ground-level $PM_{2.5}$ concentration is 61 $\mu g/m^3$ (25 $\mu g/m^3$ due to Plant operations), and the maximum estimated ground-level 285-day-period-average $PM_{2.5}$ concentration is 38 $\mu g/m^3$ (2.4 $\mu g/m^3$ 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 $PM_{2.5}$ concentration than operations after April, and the maximum estimated 24-hour-average $PM_{2.5}$ concentration occurred before April.

For the duration of the Order, the maximum 24-hour-average concentration at the top of Marina Towers is 76 $\mu g/m^3$ (41 $\mu g/m^3$ due to Plant operations), and the maximum 285-day-period-average concentration at the top of Marina Towers is 18 $\mu g/m^3$ (3.9 $\mu g/m^3$ 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 $PM_{2.5}$ 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 $\mu g/m^3$ (23 $\mu g/m^3$ due to Plant operations), and the maximum estimated concentration on the top of Marina Towers would be 79 $\mu g/m^3$ (43 $\mu g/m^3$ due to Plant operations). The estimated maximum 24-hour average occurs during non-outage periods. The estimated maximum annual average ground-level $PM_{2.5}$ concentration would be 18 $\mu g/m^3$ (4.0 $\mu g/m^3$ due to Plant operations), and the estimated maximum concentration at the top of Marina Towers would be 20 $\mu g/m^3$ (5.7 $\mu g/m^3$ 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 Orde*r, 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, CO_2, methane, nitrous oxide, O_3, 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 CO_2, which has increased about 30% in concentration over the last century. Fossil fuel burning is the primary contributor to increasing concentrations of CO_2 (IPCC 2001). The increasing CO_2 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 CO_2 is relatively stable in the atmosphere and essentially uniformly mixed throughout the troposphere and stratosphere, the climatic impact of CO_2 emissions does not depend upon their source location on the earth. Instead, an increase in CO_2 emissions from a specific source is effective in contributing to global increases in CO_2 concentrations.

Carbon dioxide emissions from the Plant involve two components: CO_2 produced by the combustion of the carbon contained in the coal and CO_2 produced by chemical reactions as the trona removes SO_2 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 CO_2. 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 CO_2.

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 CO_2. 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 CO_2 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 CO_2. 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 SO_2 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 SO_2 in the stack gases. With the addition of heat CO_2 is released from trona in a calcining reaction. This results in approximately 0.009 lb of CO_2 being released from trona for each pound of coal burned. The resulting quantities of the CO_2 released from trona, as shown in Table 4.3.1-3, are a very small fraction of the CO_2 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 CO_2 (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.
[a]Includes 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 SO_2 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 SO_2 in the air can cause temporary breathing difficulty for people with asthma who are active outdoors. Longer-term exposures to high levels of SO_2 gas and particles cause respiratory illness and aggravate existing heart disease. SO_2 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 mortality[27] 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 SO_2 concentrations for a 36-mi^2 (93-km^2) 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.

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[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. Sjoreen, 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/m^3, 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 SO_2 represents a significant proportion of the Plant's pollutant output, and SO_2 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 SO_2 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 SO_2, 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-mi^2 (93-km^2) 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 SO_2 and PM_{10}, the expected incidence of premature mortality among the 144,000 adults (30 and older) in a 36-mi^2 (93-km^2) 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 that SO_2.

- 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).

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 a 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.

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 SO_2 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.

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.

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.

- 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 SO_2 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%).

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 SO_2 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 SO_2, 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 m^3/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 m^3/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 m^3/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 m^3/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 m^3/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 NO_2; 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 SO_2 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 SO_2 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. SO_2 emissions also increased relative to pre-Order operations, but the use of trona caused emission of less than 45% of the SO_2 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 SO_2 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 m^3/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 m^3/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 finfish[31] 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 olmstedi*]) 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 yd^3 (1.58 million m^3);
- ash placed in the landfill has an in-place density of 1.1 ton per yd^3 (760 kg per m^3); 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 yd^3 (206,000 m^3), which is somewhat less than the historical annual disposal rate of 278,000 yd^3 (213,000 m^3) 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 yd^3 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 yd^3/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 yd^3/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 SO_2 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; $Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O$) 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_2O)	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 m^3) 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 SO_2 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 SO_2 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 SO_2 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% SO_2 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 many 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, (October13, 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.

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[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 theortetical 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 DCPCS 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.

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[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.

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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 ("S02"), 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 51ug/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 SO2 Rate - Lb/MBtu	3-Hr Rolling SO2 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 SO_2 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 $\mu g/m^3$).

(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 $\mu g/m^3$, 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 $\mu g/m^3$.

(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 $\mu g/m^3$).

(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 $\mu g/m^3$, 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 $\mu g/m^3$.

(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 $\mu g/m^3$, Mirant shall adjust its operations so that the annual, measured ambient concentration of SO2 does not exceed 80 $\mu g/m^3$.

(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(l) 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 NOx 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 exceedences.'' 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

[1] 107 FERC ¶ 62,053.

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

[1] 107 FERC ¶ 62,287.

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.

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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 (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,

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 endangeredspecies 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 (SO_2) 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 SO_2 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 (SO_2) 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 SO_2 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

File Code: Sec 7 DOE Mirant Potomac Generating Station
PCTS I/NER/2006/04102

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,

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.

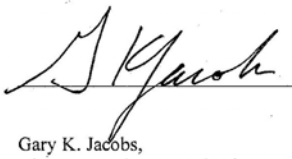
Financial or Other Interests

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.

Pozzolanic - 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

General Offices:
One Energy Plaza Tel: (517) 788-0550
Jackson, MI 49201 Fax: (517) 768-3644

*Washington Office:
1730 Rhode Island Ave. N.W. Tel: (202) 778-3340
Suite 1007
Washington, DC 20036 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. GLEESPEN
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. Sinkwitts
Theresa A.G. Staley
Janae M. Thayer
Anne M. Uitvlugt
Aaron L. Vorce
Attorney

April 20, 2022

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

RE: Case No. U-21090 – In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.

Dear Ms. Felice:

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.

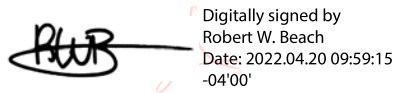
Energy Michigan Inc., Wolverine Power Supply Cooperative Inc., the Mackinac Center for Public Policy, Residential Customer Group, the Biomass Merchant Plants[1], and the Association of Businesses Advocating Tariff Equity have not signed the settlement and have not indicated that they will sign a statement 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,



Robert W. Beach

cc: Parties per Attachment 1 to the Proof of Service

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting approval of the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge ("ALJ") Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff ("Staff"); the Attorney General; Hemlock Semiconductor Operations, LLC ("HSC"); the Biomass Merchant Plants ("BMPs")[1]; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club ("MNS"); Great Lakes Renewable Energy

[1] The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association ("GLREA"), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations ("CEO")); Residential Customer Group ("RCG"); Association of Businesses Advocating Tariff Equity ("ABATE"); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, "Michigan EIBC/IEI/CGA"); Energy Michigan, Inc. ("Energy Michigan"); Midland Cogeneration Venture Limited Partnership ("MCV"); Michigan Electric Transmission Company, LLC ("METC"); Michigan Public Power Agency ("MPPA"); Wolverine Power Supply Cooperative ("Wolverine"); the Citizens Utility Board ("CUB"); the Mackinac Center for Public Policy ("Mackinac"); and the Urban Core Collective ("UCC"). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company's IRP Proposed Course of Action ("PCA") in its entirety, as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

(i.) Approve Consumers Energy's PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;

(ii.) Approve the Company's acquisition and proposed purchase costs for the New Covert Generating Facility ("Covert Plant") and Dearborn Industrial Generation ("DIG Plant"), the Livingston Generating Station ("Livingston Plant"), and the Kalamazoo River Generating Station ("Kalamazoo Plant"), in the manner proposed by the Company, and proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP;

(iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

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

(v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;

(vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;

(vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and

(viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR ($23,751,000), CVR ($9,736,315), and the purchase of the Covert Plant ($815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits ("ZRCs")) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

3. The parties agree to the approval of the battery deployment program as proposed by Company witness Richard T. Blumenstock. The parties agree that the Company will conduct stakeholder outreach to solicit feedback regarding the battery deployment program prior to the issuance of the first battery deployment program competitive solicitation. The approval to recover the costs associated with the batteries acquired in the battery deployment program will be sought in future electric rate cases.

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. ("MISO") or other emergent issues within the Company's generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and

b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;

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

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

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

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

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

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

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

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at $26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and

b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;

b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled "Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and "Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination." The "Objective" of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission's adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;

d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;

e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;

f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company's next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);

g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;

h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company's competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and

j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;

b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;

c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;

d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;

f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and

g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate $2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund ("VRR"). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level ("FPL"), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company's next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds ("VOCs"), and primary particulate matter ("PM2.5");

b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant's emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;

c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool ("EJSCREEN"), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;

d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;

e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and

f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;

b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;

c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;

d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;

e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;

f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;

g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;

h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;

i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;

b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;

c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and

d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler Digitally signed by Spencer Sattler Date: 2022.04.19 14:00:30 -04'00' Date: April 19, 2022

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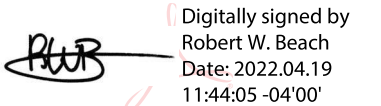
CONSUMERS ENERGY COMPANY

By: 

Date: April 19, 2022

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Bret A. Totoraitis (P72654)
Robert W. Beach (P73112)
Anne M. Uitvlugt (P71641)
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ATTORNEY GENERAL, DANA NESSEL

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

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GREAT LAKES RENEWABLE ENERGY ASSOCIATION

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

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MICHIGAN ENVIRONMENTAL COUNCIL

By: Digitally signed by Christopher M. Bzdok Date: 2022.04.19 12:05:00 -04'00'

Date: April 19, 2022

Christopher M. Bzdok, Esq.
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NATURAL RESOURCES DEFENSE COUNCIL

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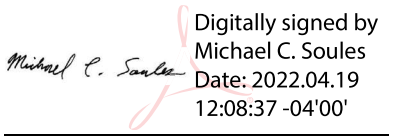
SIERRA CLUB

By:  Date: April 19, 2022

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CITIZENS UTILITY BOARD OF MICHIGAN

By: _____ Date: April 19, 2022

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

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

Date: April 19, 2022

Laura A. Chappelle, Esq.
Justin K. Ooms, Esq.
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MICHIGAN ELECTRIC TRANSMISSION COMPANY, LLC

By: Richard Aaron

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

By: Date: April 19, 2022

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Environmental Law & Policy Center
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Grand Rapids, Michigan 49503

HEMLOCK SEMICONDUCTOR OPERATIONS LLC

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

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URBAN CORE COLLECTIVE

By: _____ Date: 19-April-2022

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Mark N. Templeton, Esq.
Robert A. Weinstock, Esq.
University of Chicago Law School –
Abrams Environmental Law Clinic
6020 South University Avenue
Chicago, IL 60637

The following parties do not wish to be signatories to this Settlement Agreement; however they have agreed to sign below to indicate non-objection to the Settlement Agreement.

MICHIGAN PUBLIC POWER AGENCY

By: Nolan J. Moody Digitally signed by Nolan J. Moody Date: 2022.04.19 12:19:10 -04'00' Date: April 19, 2022

Nolan J. Moody, Esq.
Peter H. Ellsworth, Esq.
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MIDLAND COGENERATION VENTURE LIMITED PARTNERSHIP

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

John A. Janiszewski, Esq.
Dykema Gossett PLLC
201 Townsend Street, Suite 900
Lansing, MI 48933

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

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

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Kimberly Flynn, Legal Assistant
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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

Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 2)

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	95.00%	13	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	95.00%	8	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	95.00%	8	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	95.00%	4	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	95.00%	15	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	95.00%	7	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	95.00%	15	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	95.00%	7	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	95.00%	11	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	95.00%	6	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	46.90%	53	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE therefore they will not be obtaining a MISO queue cycle
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Winter Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	95.00%	8	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	95.00%	1	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	95.00%	15	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	95.00%	8	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	95.00%	6	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	95.00%	0	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	95.00%	0	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	95.00%	5	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	95.00%	1	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	95.00%	0	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Storage	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	99.12%	1	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED
UNDER SEAL WITH THE MPSC

SPRING
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 1
Page: 1 of 1

Exhibit 1 - Utility Bundled Service Peak Demand for Michigan MISO LRZ 7 - Spring Season

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,428	6,800	6,886	6,977	7,001
2	Choice, Coincident to Service Territory	362	582	444	428	420
3	Bundled (line 1 - line 2)	6,066	6,218	6,441	6,549	6,581
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,342	6,708	6,793	6,882	6,906
5	Choice, Coincident to Service Territory	357	574	438	422	415
6	Bundled (line 4 - line 5)	5,984	6,134	6,354	6,460	6,492

* Totals carry over to Exhibit 2.
* Provide actual values where available.
* Assume current proportions of Bundled service and Choice service throughout the forecast period unless there is a known change in electric service provider.
* Do not adjust for Load Modifying Resources or Demand Response Programs. Those adjustments will be accounted for in Exhibit 2.
* Actuals include net effect of demand-side management and transmission losses. Forecasted values exclude these effects.

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 2
Page: 1 of 1

Exhibit 2 - Planning Reserve Margin Requirements and Planning Resources to be Acquired (ZRC) - Spring Season

Line	(a)	(b) PY 2025-26	(c) PY 2026-27	(d) PY 2027-28	(e) PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,218	6,441	6,549	6,581
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	808	843	862	861
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,410	5,599	5,686	5,720
4	Load Diversity Factor coincident to MISO, %.	98.65%	98.65%	98.65%	98.65%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,337	5,523	5,609	5,643
6	Transmission Losses, %	3.20%	3.20%	3.20%	3.20%
7	Planning Reserve Margin % UCAP Basis	25.30%	30.70%	32.80%	33.10%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,901	7,450	7,688	7,751
9	Company Owned, In-State, Non-Intermittent, ZRC	4,022	3,742	3,927	3,749
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	175	713	957	1,198
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	16	21	21	21
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,230	4,493	4,922	4,985
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	412	380	393	394
19	PPA, In-State, Non-Intermittent, ZRC	1,603	1,603	1,550	1,418
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	32	26	26	26
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	408	673	918	991
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	21	21	21	21
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	23	23
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	185	185	185	185
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,249	2,514	2,723	2,663
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	-
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	6,986	7,457	8,037	8,042
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	85	7	350	292

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 3
Page: 1 of 1

Exhibit 3 - Demand Response - Capacity Resources - Spring Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	46	14	60
5		DR RATE GI REDUCE BY	16	5	21
6		DR RATE GI REDUCE TO	257	75	332
9					-
10					-
11	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				412.4
12	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
13		Rate EIP	10	4	14
14		DR CONTRACTS	-	-	-
16		DR RATE GI REDUCE BY	15	5	21
17		DR RATE GI REDUCE TO	257	90	346
20					-
21					-
22	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				380.3
23	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
24		Rate EIP	15	6	21
25		DR CONTRACTS	-	-	-
27		DR RATE GI REDUCE BY	15	6	21
28		DR RATE GI REDUCE TO	257	95	352
31					-
32					-
33	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				393.2
34	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
35		Rate EIP	15	6	21
36		DR CONTRACTS	-	-	-
38		DR RATE GI REDUCE BY	15	6	21
39		DR RATE GI REDUCE TO	257	96	352
42					-
43					-
44	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				394.1

EXHIBIT 4
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 5
Page: 1 of 1

Exhibit 5 - New or Upgraded Generation Owned - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	82.00%	18	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

[1] The projects are interconnected with CE therefore they will not be obtaining a MISO queue cycle
[2] Construction Start date is based on the Company issuing a Limited Notice to Proceed and Construction End date is subject to successful outcome of all appeals associated with the Special Land Use Permit
[3] Construction Start and End Date subject to Invenergy successfully obtaining SLUP by Q4 2025

EXHIBIT 6
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No: U-21775
Utility: Consumers Energy Company
Date: February 24, 2025
Exhibit: 7
Page: 1 of 1

Exhibit 7 - New or Upgraded Purchased Power - Spring Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Queue Date	(i) Planned MISO Interconnection Agreement Approval	(j) Construction Start Date	(k) Construction End Date
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	87.50%	3	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Solar	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	85.44%	17	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

EXHIBIT 8
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 9
IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC

EXHIBIT 10
IS *CONFIDENTIAL* AND BEING FILED
UNDER SEAL WITH THE MPSC

EXHIBIT 11
IS *CONFIDENTIAL* AND BEING FILED
UNDER SEAL WITH THE MPSC

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-14.00
Cancels Sixth Revised Sheet No. D-14.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

Subject to any restrictions, this rate is available to any Full Service Customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purpose of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage; or (v) Rule C5.5 – Non-Transmitting Meter Provision participants.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.086217*	$ *0.005990*	$*0.092207*	per kWh for Off-Peak kWh between June 1 and September 30
$ *0.132272*	$ *0.008912*	$*0.141184*	per kWh for On-Peak kWh between June 1 and September 30
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for all kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-15.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Senior Citizen Provision)

Third Revised Sheet No. D-15.00
Cancels Second Revised Sheet No. D-15.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-16.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-16.00
Cancels Fifth Revised Sheet No. D-16.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Device Cycling Program

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning and water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate is determined solely by the Company and Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

(Continued on Sheet No. D-17.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-17.00
Cancels Fourth Revised Sheet No. D-17.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(0.019625)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-18.00)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page)

Second Revised Sheet No. D-18.00
Cancels First Revised Sheet No. D-18.00

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B, Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, June 1 through September 30, including weekday holidays when applicable:

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To combine and cancel tariff sheets)

First Revised Sheet No. D-19.00
Cancels Original Sheet No. D-19.00

These sheets have been cancelled and are reserved for future use:

Original Sheet No. D-20.00 is cancelled; First Revised Sheet No. D-20.00 is reserved for future use
Original Sheet No. D-21.00 is cancelled; First Revised Sheet No. D-21.00 is reserved for future use
Original Sheet No. D-22.00 is cancelled; First Revised Sheet No. D-22.00 is reserved for future use
First Revised Sheet No. D-23.00 is cancelled; Second Revised Sheet No. D-23.00 is reserved for future use
Original Sheet No. D-24.00 is cancelled; First Revised Sheet No. D-24.00 is reserved for future use
Original Sheet No. D-25.00 is cancelled; First Revised Sheet No. D-25.00 is reserved for future use
Original Sheet No. D-26.00 is cancelled; First Revised Sheet No. D-26.00 is reserved for future use
First Revised Sheet No. D-27.00 is cancelled; Second Revised Sheet No. D-27.00 is reserved for future use
First Revised Sheet No. D-28.00 is cancelled; Second Revised Sheet No. D-28.00 is reserved for future use
Original Sheet No. D-29.00 is cancelled; First Revised Sheet No. D-29.00 is reserved for future use
Original Sheet No. D-30.00 is cancelled; First Revised Sheet No. D-30.00 is reserved for future use
Original Sheet No. D-31.00 is cancelled; First Revised Sheet No. D-31.00 is reserved for future use
First Revised Sheet No. D-32.00 is cancelled; Second Revised Sheet No. D-32.00 is reserved for future use
Original Sheet No. D-33.00 is cancelled; First Revised Sheet No. D-33.00 is reserved for future use
Original Sheet No. D-34.00 is cancelled; First Revised Sheet No. D-34.00 is reserved for future use
First Revised Sheet No. D-35.00 is cancelled; Second Revised Sheet No. D-35.00 is reserved for future use

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-36.00
Cancels Sixth Revised Sheet No. D-36.00

RESIDENTIAL SMART HOURS RATE RSH

Availability:

Subject to any restrictions, this rate is available to any Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, maintain and own the required equipment at the customers' premises at the Company's request. By selecting this rate schedule, the customer agrees to provide an email address. Electric consumption is billed using on-peak and off-peak periods year-round on the Residential Smart Hours Rate.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

	Non-Capacity	Capacity	Total	
Off-Peak – Summer	$*0.086217*	$*0.005990*	$*0.092207*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak – Summer	$*0.132272*	$*0.008912*	$*0.141184*	per kWh for all On-Peak kWh between June 1 and September 30
Off-Peak – Winter	$*0.080987*	$*0.004518*	$*0.085505*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak – Winter	$*0.091448*	$*0.005139*	$*0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$*0.074267*	per kWh for all kWh for a Full Service customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-36.10)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company **Original Sheet No. D-36.10**
(To reformat page revise Senior Citizen Service Provision)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty Level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

Senior Citizen Service Provision (RSC):

When service is supplied to the *Principal* Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

(Continued on Sheet No. D-37.00)

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 20, 2023

Issued under authority of the Michigan Public Service Commission dated January 19, 2023 in Case No. U-21224

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Seventh Revised Sheet No. D-37.00
Cancels Sixth Revised Sheet No. D-37.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.10)

Monthly Rate: (Contd)

Device Cycling Program

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning *and* water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate is determined solely by the Company *and* Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heater equipment, while customers with air conditioning equipment will experience load management during the summer billing months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June – September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

(Continued on Sheet No. D-38.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-38.00
Cancels Fourth Revised Sheet No. D-38.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Effective Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward:	$(1.00)	per kWh of incremental energy reduction during a critical peak event

Critical Peak Price

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price:	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount:	$(0.019625)	per kWh of Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-39.00)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Residential Electric Vehicle Program reference)

Fourth Revised Sheet No. D-39.00
Cancels Third Revised Sheet No. D-39.00

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2., Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2., Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1*., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

(1) On-Peak Hours: 2:00 PM to 7:00 PM
(2) Off-Peak Hours: 7:00 PM to 2:00 PM

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Eighth Revised Sheet No. D-40.00
Cancels Seventh Revised Sheet No. D-40.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; (iv) any other Non-Residential usage or (v) customers being served under Rule C5.5 Non-Transmitting Meter Provision.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this program only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this program shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	$0.072762	$0.004114	$0.076876	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	$0.096349	$0.006757	$0.103106	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	$0.132272	$0.008912	$0.141184	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	$0.070062	$0.003564	$0.073626	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	$0.091004	$0.004969	$0.095973	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	$0.091448	$0.005139	$0.096587	per kWh for all On-Peak kWh between October 1 and May 31

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: These charges are applicable to Full Service Customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.074267	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-40.50)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page)

Original Sheet No. D-40.50

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-41.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-41.00
Cancels Fifth Revised Sheet No. D-41.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.50)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service Customers.

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) and shall not be applied to more than one account per Principal Residence Customer.

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the separately metered electric vehicle will be billed under the Residential Nighttime Savers Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 50 amperes or 9.6 kW.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

Delivery Charges: These charges are applicable to Full Service Customers.

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Device Cycling Program:

A customer who is taking service from the Company may be eligible to participate in the Company's voluntary Device Cycling Program for load management of eligible electric equipment, including air conditioning and water heaters. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Customer eligibility to participate in this program is determined solely by the Company and Device Cycling Program Credits may be taken in conjunction with one another. The Company will accept a customer's qualifying electric equipment under this program only if it has the capability to be controlled by the Company or with a contractual agreement with a landlord if the customer is not the property owner. The Company will install the required equipment at the premises which will allow load management upon signal from the Company. When load management equipment is installed at a premises, future customers will be auto-enrolled into the Device Cycling Program. Upon move in, the customer will be notified confirming participation in the Device Cycling Program and will have 30 days to opt out. Such equipment shall be furnished, installed, maintained and owned by the Company at the Company's expense. Equipment installations must conform to the Company's specifications.

Customers can elect to participate in the Device Cycling Program and the Peak Reward Program as described in this tariff. When a customer participates in both programs, the customer's credit earned from their incremental energy savings through Peak Reward is compared to the total credit earned under the Device Cycling Program. The greater of the two credits will be applied to the customer's invoice for that billing month. Both credits will not apply in a single billing month.

The Company reserves the right to specify the term or duration of the program. The customer's enrollment shall be terminated if the voluntary program ceases, if the customer tampers with the control switch or the Company's equipment or any reasons as provided for in Rule C1.3, Use of Service. The Company reserves the right to call test events between October 1 and May 31 for customers participating in the Device Cycling Program.

(Continued on Sheet No. D-42.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-42.00
Cancels Fifth Revised Sheet No. D-42.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Device Cycling Program: (Contd)

Load management may occur on non-holiday weekdays between the hours of 7:00 AM and 8:00 PM for no more than an eight hour period in any one day throughout the year for customers with water heating equipment, while customers with air conditioning equipment will experience load management during the summer months of June through September only. Load management may be implemented for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may occur on any day, during any hour, and for any length of time during a declared emergency event as directed by MISO.

The Customer may contact the Company to request to override a load management event for one load management event during the June through September months in any one calendar year for the balance of the hours left in that load management event with no penalty. The request shall be granted at the discretion of the Company. If the override request was granted by the Company and the customer requests and is granted any additional overrides in the same calendar year, the Device Cycling Credit may be forfeited for that billing month.

Rule C1.1 Character of Service, Rule C3 Emergency Electrical Procedures and other rules and regulations contained in the Company's Electric Rate Book apply to customers taking service under this Peak Power Savers – Device Cycling Program.

The monthly credit(s) for the Peak Power Savers Program shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Air Conditioner Peak Cycling Credit:	$(8.00)	per customer per month during the billing months of June-September
Water Heater Cycling Credit:	$(1.88)	per customer per month for all billing months

Peak Reward:

Participating customers are able to manage electric costs by reducing load during critical peak events. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30 and up to five critical peak events between October 1 and May 31. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer. In the circumstance that MISO declares a maximum Generation Emergency Event, participating customers may receive a critical peak event communication without a guarantee of advance notice. The maximum Generation Emergency Event will be in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall receive a standard credit of $3.00 for participation in the control group for the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Peak Reward Enrollment transferred to their new premises, unless a request for cancelation is submitted to the Company.

During a critical peak event, customers on will be credited the Peak Reward per kWh of incremental energy reductions. Customers participating in the Peak Reward Program cannot participate in the Critical Peak Price Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Peak Reward	$(1.00)	per kWh of incremental energy reduction during a critical peak event

(Continued on Sheet No. D-43.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-43.00
Cancels Fourth Revised Sheet No. D-43.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Critical Peak Price:

Participating customers are able to manage electric costs by shifting load during critical peak events to a lower cost pricing period. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company may call up to fourteen critical peak events between June 1 and September 30. Customers will be notified by 11:59 PM the day before a critical peak event is expected to occur. Receipt of such notice is the responsibility of the participating customer.

A control group will be established for each critical peak event. Control group participants will not receive notice and shall not be penalized for not participating in the critical peak event. Customers may be assigned to a maximum of two control groups per event season.

Customers must have a transmitting meter to participate in Peak Power Savers. Customers who relocate within the Consumers Energy electric service territory will have their Critical Peak Price enrollment transferred to their new premises, unless a request for cancellation is submitted to the Company.

During a critical peak event, customers on will be charged the Critical Peak Price per kWh consumed during the critical peak event. Customers participating in the Critical Peak Price Program cannot participate in the Peak Reward Program.

Power Supply Charges: These charges are applicable to Full Service Customers.

Critical Peak Price	$1.00	per kWh of energy consumed during a critical peak event between June 1 and September 30
Off-Peak Discount	$(0.019625)	per kWh for Off-Peak kWh between June 1 and September 30

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C 11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provision contained in Rule C 11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-44.00)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Residential Electric Vehicle Program)

Fourth Revised Sheet No. D-44.00
Cancels Third Revised Sheet No. D-44.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1*., Residential Electric Vehicle Program.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-44.10
Cancels Fifth Revised Sheet No. D-44.10

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, except as provided for below.

Service for charging Electric Vehicles is available on this rate and shall not exceed 9.6 kW, except as provided for below. Electric Vehicle charging equipment is not included in the total connected load of the home for purposes of this section.

Individual equipment exceeding 3 hp or 3 kW, Electric Vehicle charging equipment exceeding 9.6 kW, or total household load exceeding 10 kW may be subject to additional charges in accordance with Rule C6., Distribution Systems, Line Extensions and Service Connections. Such charges shall only apply to the extent the cost exceeds that of ensuring the connecting equipment matches that provided as standard to new residential customers.

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for the first 600 kWh per month during the billing months of June - September
$ *0.132272*	$ *0.008912*	$*0.141184*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-44.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise price)

Sixth Revised Sheet No. D-44.20
Cancels Fifth Revised Sheet No. D-44.20

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access customers.

System Access Charge:	$8.00	per customer per month
Distribution Charge:	$0.074267	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the total household income does not exceed 150% of the Federal Poverty level, a credit shall be applied during all billing months. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following in the past 12 months:

1. A Home Heating Credit energy draft
2. State Emergency Relief
3. Assistance from a Michigan Energy Assistance Program (MEAP)
4. Medicaid

If a customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for the Income Assistance Service Provision (RIA) shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Income Assistance Credit: $(8.00) per customer per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges.

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

Low Income Assistance Credit (LIAC):

Company selected Residential customers may receive LIAC for up to 12 consecutive months. The number of customers enrolled may be adjusted, at the Company's discretion, in order to dispense Commission-approved LIAC funding on an annual basis. Any shortfall in the dispensing of annual LIAC funds to qualified customers shall be carried over into the subsequent LIAC program year. LIAC customer selection will be based on highest need and with total household income that does not exceed 150% of the Federal Poverty level. The total household income is verified when the customer has provided proof that they have received, or are currently participating in, one or more of the following within the past 12 months:

1. Customers whose total household income does not exceed 150% of the Federal Poverty level within the last 12 months
2. Customers who have received assistance from a Michigan Energy Assistance Program (MEAP)
3. Customers who have received a Home Heating Credit energy draft
4. A State Emergency Relief program
5. Medicaid
6. Customers that have participated in a Supplementary Nutrition Assistance Program where the total household income does not exceed 150% of the Federal Poverty level within the last 12 months.

If the customer does not meet any of the above requirements, a low-income verification form will be provided by the Company for the customer to complete and return.

The monthly credit for LIAC shall be applied as follows:

Low Income Assistance Credit: $(30.00) per meter per month

If a credit balance occurs, the credit shall apply to the customer's future electric utility charges. Re-enrollment, if applicable, and confirmation of qualification is required for each annual period of participation.

Customers selected for LIAC will not be eligible for the RIA Provision while enrolled in LIAC.

(Continued on Sheet No. D-44.30)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page and revise Senior Citizen Service Provision)

Second Revised Sheet No. D-44.30
Cancels First Revised Sheet No. D-44.30

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.20)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

When service is supplied to the Principal Residence Customer who is 65 years of age or older and head of household, a credit shall be applied during all billing months.

The monthly credit for the residential Senior Citizen Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

Senior Citizen Credit: $(4.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Income Assistance Service Provision (RIA) *and shall not be applied to more than one account per Principal Residence Customer.*

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, adjusted for qualified service provision credit and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer's bill shall be 21 days from the date of transmittal. A late payment charge of 2%, not compounded, of the portion of the bill, net of taxes, shall be assessed to any bill that is delinquent. A customer who participates in the Winter Protection Plan or who is 65 years of age or older and who has notified the Company the customer is 65 years of age or older, shall be exempt from a late payment charge as described in Rule B2., Consumer Standards and Billing Practices for Electric and Natural Gas Service, R 460.125, Late payment charges.

Term and Form of Contract:

Service under this rate shall not require a written contract except for the Green Generation Program participants.

Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 3)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update prices)

Sixth Revised Sheet No. D-45.00
Cancels Fifth Revised Sheet No. D-45.00

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	Capacity	Total	
$0.094566	$0.006246	$0.100812	per kWh for all kWh during the billing months of June-September
$0.082686	$0.004372	$0.087058	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.057594	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-46.00
Cancels Fifth Revised Sheet No. D-46.00

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-47.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fourth Revised Sheet No. D-47.00
Cancels Third Revised Sheet No. D-47.00

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, (vii) service under the Demand Response Program or (viii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-48.00
Cancels Fifth Revised Sheet No. D-48.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: These charges are applicable to Full Service Customers.

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$*0.073219*	$*0.004064*	$*0.077283*	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	$*0.098057*	$*0.006297*	$*0.104354*	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	$*0.132113*	$*0.007579*	$*0.139692*	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	$*0.071813*	$*0.003541*	$*0.075354*	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	$*0.091062*	$*0.004740*	$*0.095802*	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-49.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-49.00
Cancels Fifth Revised Sheet No. D-49.00

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $(0.017673) per kWh for all kWh

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-50.10)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Second Revised Sheet No. D-50.10
Cancels First Revised Sheet No. D-50.10

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Demand Response Program or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-51.00
Cancels Fifth Revised Sheet No. D-51.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$*25.91*	$*1.69*	$*27.60*	per kW for all kW of Peak Demand during the billing months of June-September
$*15.05*	$*1.50*	$*16.55*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.032152*	per kWh for all kWh during the billing months of June-September
$*0.029959*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factors shown on Sheet No. D-6.00.

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	$*0.043515*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-52.00)

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Garrick J. Rochow,
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Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Adjustment for Power Factor)

First Revised Sheet No. D-52.00
Cancels Original Sheet No. D-52.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-51.00)

Monthly Rate: (Contd)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) *If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.*

(b) *If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:*

Power Factor	***Penalty***
0.800 to 0.849	*0.50%*
0.750 to 0.799	*1.00%*
0.700 to 0.749	*2.00%*
Below 0.700	*3% first 2 months*

Adjustment for Power Factor shall not be applied when the Peak Demand is based a Minimum Peak Billing Demand.

(c) *A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.*

Peak Demand:

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-53.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-53.00
Cancels Fourth Revised Sheet No. D-53.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Education Institution Credit:	$ (0.000690)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges – These charges are applicable to Full Service Customers.

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Second Revised Sheet No. D-53.50
Cancels First Revised Sheet No. D-53.50

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

(Continued on Sheet No. D-54.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat page and revise Term and Form of Contract)

Third Revised Sheet No. D-54.00
Cancels Second Revised Sheet No. D-54.00

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. *D-53.50*)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, (v) *service under the Demand Response Program or (vi)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after January 20, 2023

Issued under authority of the Michigan Public Service Commission dated January 19, 2023 in Case No. U-21224

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-55.00
Cancels Fourth Revised Sheet No. D-55.00

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.089336	*$0.005350*	*$0.094686*	per kWh for all kWh during the billing months of June-September
$0.078143	*$0.003744*	*$0.081887*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.088260	*$0.005267*	*$0.093527*	per kWh for all kWh during the billing months of June-September
$0.077219	*$0.003687*	*$0.080906*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.087186	*$0.005192*	*$0.092378*	per kWh for all kWh during the billing months of June-September
$0.076290	*$0.003634*	*$0.079924*	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-56.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-56.00
Cancels Fifth Revised Sheet No. D-56.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

Delivery Charges: These charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $*0.020826* per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $*0.009094* per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $*0.002634* per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-57.00
Cancels Fifth Revised Sheet No. D-57.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $ (0.001741) per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $ (0.001309) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(0.000533) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-58.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fifth Revised Sheet No. D-58.00
Cancels Fourth Revised Sheet No. D-58.00

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customers as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate may require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, (v) service under the Demand Response Program or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-59.00
Cancels Fourth Revised Sheet No. D-59.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers

Charges for Customer Voltage Level 3 (CVL 3)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.51*	$*1.81*	$*18.32*	per kW of On-Peak Billing Demand during the billing months of June-September
$*14.26*	$*1.68*	$*15.94*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity	
$*8.17*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.60*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.045475*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.029051*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034757*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.030290*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-60.00
Cancels Fourth Revised Sheet No. D-60.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.33*	$*1.79*	$*18.12*	per kW of On-Peak Billing Demand during the billing months of June-September
$*14.10*	$*1.65*	$*15.75*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity	
$*8.04*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.49*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.044977*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.028732*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034376*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029959*	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.14*	$*1.76*	$*17.90*	per kW of On-Peak Billing Demand during the billing months of June-September
$*13.94*	$*1.63*	$*15.57*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity	
$*7.93*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.38*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.044461*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.028403*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.033982*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.029615*	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-61.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-61.00
Cancels Fifth Revised Sheet No. D-61.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$5.94	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$3.10	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$0.90	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

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Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-62.00
Cancels Fifth Revised Sheet No. D-62.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges: These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.55) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-63.00
Cancels Fourth Revised Sheet No. D-63.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges:	**These charges are applicable to Full Service and Retail Open Access Customers.**	
Educational Institution Credit:	$(0.000176)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Sixth Revised Sheet No. D-64.00
Cancels Fifth Revised Sheet No. D-64.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Third Revised Sheet No. D-65.00
Cancels Second Revised Sheet No. D-65.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

Conditions of Interruption (Contd)
Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption
Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

Interruptible Service Provision – Market-Price Option (GI2):

Availability:

This provision is available to any Full Service GPD customer account willing to designate at least 3,000 kW of On-Peak Billing Demand as Defined Interruptible Capacity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of designated interruptible load available to any single customer, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to designate less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm Capacity and Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 10th of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

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President and Chief Executive Officer,
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-66.00
Cancels Sixth Revised Sheet No. D-66.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.037344	per kWh for all kWh during the billing months of June-September
	$0.034532	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 2 (CVL 2)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.036398	per kWh for all kWh during the billing months of June-September
	$0.032629	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 1 (CVL 1)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$0.032631	per kWh for all kWh during the billing months of June-September
	$0.029082	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	0.992%
Customer Voltage Level 2	1.313%	2.239%
Customer Voltage Level 3	3.366%	6.948%

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise MISO Emergency Electrical Procedure reference)

Second Revised Sheet No. D-67.00
Cancels First Revised Sheet No. D-67.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-68.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Third Revised Sheet No. D-68.00
Cancels Second Revised Sheet No. D-68.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Definitions.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

(Continued on Sheet No. D-69.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Term and Form of Contract)

Second Revised Sheet No. D-69.00
Cancels First Revised Sheet No. D-69.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate: (Contd)

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, (vi) *service under the Demand Response Program or (vii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Schedule of Hours)

Second Revised Sheet No. D-70.00
Cancels First Revised Sheet No. D-70.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.

This rate is not available for Standby service with generators that exceed 550kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to *2:00* PM and *6:00* PM to 11:00 PM
Mid-Peak Hours:	*2:00* PM to *3:00* PM and 5:00 PM to *6:00* PM
High-Peak Hours:	*3:00* PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to *4:00* PM and *8:00* PM to 12:00 AM
Mid-Peak Hours:	*4:00* PM to *5:00* PM and 7:00 PM to *8:00* PM
High-Peak Hours:	*5:00* PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-71.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-71.00
Cancels Fifth Revised Sheet No. D-71.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.067289	$0.003182	$0.070471	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.082596	$0.004711	$0.087307	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.108883	$0.005865	$0.114748	per kWh during the calendar months of June-September
High-Peak-Summer	$0.124771	$0.006144	$0.130915	per kWh during the calendar months of June-September
Off-Peak -Winter	$0.073740	$0.003391	$0.077131	per kWh during the calendar months of October-May
Mid-Peak -Winter	$0.082502	$0.003940	$0.086442	per kWh during the calendar months of October-May
High-Peak -Winter	$0.087588	$0.003941	$0.091529	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.066492	$0.003133	$0.069625	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.081602	$0.004638	$0.086240	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.107579	$0.005775	$0.113354	per kWh during the calendar months of June-September
High-Peak-Summer	$0.123288	$0.006049	$0.129337	per kWh during the calendar months of June-September
Off-Peak - Winter	$0.072869	$0.003339	$0.076208	per kWh during the calendar months of October-May
Mid-Peak - Winter	$0.081524	$0.003879	$0.085403	per kWh during the calendar months of October-May
High-Peak - Winter	$0.086554	$0.003880	$0.090434	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.065692	$0.003088	$0.068780	per kWh during the calendar months of June-September
Low-Peak-Summer	$0.080610	$0.004572	$0.085182	per kWh during the calendar months of June-September
Mid-Peak-Summer	$0.106276	$0.005692	$0.111968	per kWh during the calendar months of June-September
High-Peak-Summer	$0.121801	$0.005963	$0.127764	per kWh during the calendar months of June-September
Off-Peak - Winter	$0.071993	$0.003291	$0.075284	per kWh during the calendar months of October-May
Mid-Peak - Winter	$0.080542	$0.003824	$0.084366	per kWh during the calendar months of October-May
High-Peak - Winter	$0.085515	$0.003825	$0.089340	per kWh during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	$5.94	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	$3.10	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	$0.90	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-72.00
Cancels Fourth Revised Sheet No. D-72.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)		
Substation Ownership Credit:	$(*0.73*)	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Substation Ownership Credit:	$(*0.55*)	per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Educational Institution Credit:	$ (*0.000176*)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

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M.P.S.C. No. 14 – Electric
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(To add Demand Response program eligibility language)

Second Revised Sheet No. D-72.10
Cancels First Revised Sheet No. D-72.10

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Monthly Rate (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* For customers who participate in the Interruptible Service Provision (GI) on this Rate Schedule, the On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use within on-peak hours during the billing month as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates. For customers who are not enrolled in the GI provision, the On-Peak Billing Demand shall not apply.

The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPTU shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

(Continued on Sheet No. D-72.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Original Sheet No. D-72.20

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.10)

Monthly Rate (Contd)

Interruptible Service Provision (GI): (Contd)

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

Power Supply Charges: These charges are applicable to Full Service Customers.

Interruptible Credit:	*$(7.00)*	*per kW of On-Peak Billing Demand during the billing months of June-September*
	$(6.00)	*per kW of On-Peak Billing Demand during the billing months of October-May*

(Continued on Sheet No. D-73.00)

Issued February 17, 2023 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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Issued under authority of the Michigan Public Service Commission dated January 19, 2023 in Case No. U-21224

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Non-Residential Electric Vehicle Programs)

Fifth Revised Sheet No. D-73.00
Cancels Fourth Revised Sheet No. D-73.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.20)

Self-Generation (SG)

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

Distributed Generation Program

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Non-Residential Electric Vehicle Programs:
The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate may require a written contract with a minimum term of one year. Service under this rate shall require a written contract for (i) service under the Educational Institution Service Provision, (ii) service under the Interruptible Service Provision, (iii) service under the Demand Response Program, or (iv) at the option of the Company.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-74.00
Cancels Fourth Revised Sheet No. D-74.00

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing or former metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Nature of Service

Service under the rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

The Company may elect to install devices that can enable direct load management, power metering, data collection, near real-time data communication and internet based monitoring. There shall be no cost to the customer associated with the system equipment or installation of the system equipment. The Company reserves the right to remove the system equipment if the customer moves from Rate EIP to another primary rate.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

(Continued on Sheet No. D-74.50)

Issued August 30, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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and after March 15, 2024

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dated March 1, 2024
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Critical Peak Event Determination)

First Revised Sheet No. D-74.50
Cancels Original Sheet No. D-74.50

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Critical Peak Event Determination

A Critical Peak Event *occurs when* the market price *exceeds* an Economic Trigger Price or a *System Integrity Event* is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at $1.00 per kWh during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-75.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-75.00
Cancels Fourth Revised Sheet No. D-75.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.50)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066902*	*$0.002547*	*$0.069449*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.088051*	*$0.003980*	*$0.092031*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.113410*	*$0.004840*	*$0.118250*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.128630*	*$0.004951*	*$0.133581*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.074119*	*$0.002771*	*$0.076890*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.085644*	*$0.003162*	*$0.088806*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.089524*	*$0.003205*	*$0.092729*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066114*	*$0.002508*	*$0.068622*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.086999*	*$0.003919*	*$0.090918*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.112061*	*$0.004765*	*$0.116826*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.127112*	*$0.004875*	*$0.131987*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.073246*	*$0.002728*	*$0.075974*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.084637*	*$0.003114*	*$0.087751*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.088472*	*$0.003155*	*$0.091627*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

(Continued on Sheet No. D-76.00)

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Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Sixth Revised Sheet No. D-76.00
Cancels Fifth Revised Sheet No. D-76.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges:

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065320*	*$0.002472*	*$0.067792*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.085947*	*$0.003863*	*$0.089810*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.110710*	*$0.004697*	*$0.115407*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.125587*	*$0.004805*	*$0.130392*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.072368*	*$0.002689*	*$0.075057*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.083623*	*$0.003069*	*$0.086692*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.087414*	*$0.003110*	*$0.090524*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: *$5.94* per kW of Maximum Demand

Charge for Customer Voltage Level 2 (CVL 2)
Capacity Charge: *$3.10* per kW of Maximum Demand

Charge for Customer Voltage Level 1 (CVL 1)
Capacity Charge: *$0.90* per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-77.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices and add Interruptible Credit)

Fifth Revised Sheet No. D-77.00
Cancel Fourth Revised Sheet No. D-77.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Monthly Rate (Contd):

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit:

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.55) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

To be eligible for Self-Generation, a Customer with a generating installation operating in parallel with the Company's system, must meet the requirements described in Rule C 11.1., Self-Generation.

(Continued on Sheet No. D-78.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Term and Form of Contract)

Third Revised Sheet No. D-78.00
Cancels Second Revised Sheet No. D-78.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-77.00)

Distributed Generation Program:

The Distributed Generation Program is available to any eligible customer as described in Rule C 11.3., Distributed Generation Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C 11.3.B., Distributed Generation Definitions.

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule C 11.3., Distributed Generation Program.

Green Generation Programs:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate *may* require a written contract with a minimum term of one year.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Availability and Terms and Conditions)

First Revised Sheet No. D-78.10
Cancels Original Sheet No. D-78.10

LARGE ECONOMIC DEVELOPMENT RATE LED

Availability:

At the Company's discretion, the Large Economic Development Rate is available to (1) new Full Service primary electric customers locating permanent operations within the Company's service territory or (2) existing Full Service primary customers expanding their permanent operations. *As of June 7, 2024, the Large Economic Development Rate is not available to data centers within the Company's service territory who have not already contracted for service under this rate.*

The minimum new or expanded incremental electric service required to contract under the Large Economic Development Rate is 35,000 kW. This rate requires a written contract specifying the terms of the electric service. Upon mutual agreement between the customer and the Company, up to 60 months from the *initial service date for billing purposes* may be granted for the customer to meet the *required 35,000 kW On-Peak Billing Demand*.

This rate is not available to a new customer resulting from a change in ownership of an existing establishment located within the Company's service area. However, if a change in ownership occurs after the customer contracts for service under this rate, the successor may be allowed to fulfill the remainder of the contract.

Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities served by the Company, for standby service, for new or expanded service for resale or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate.

Terms and Conditions:

This rate requires a contract term, the minimum term under this rate is fifteen (15) years from the date initial service is provided under this rate. *The maximum contract term under this rate shall not exceed twenty (20) years from the initial service date for billing purposes.*

If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:

Up to 50% of the contract term	100%
More than 50 to 60% of the contract term	83%
More than 60 to 70% of the contract term	67%
More than 70 to 80% of the contract term	50%
More than 80 to 90% of the contract term	33%
More than 90% to 99.9% of the contract term	17%

For existing customers expanding their operations, the Company will install, operate, and maintain the metering equipment necessary to measure the incremental load to be billed under this rate. The customer will provide the Company with access to its metering equipment. The Company is not obligated to extend, expand, or rearrange its facilities if it determines the existing facilities are adequate to serve the customer's load.

(Continued on Sheet D-78.20)

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Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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Issued under authority of the Michigan Public Service Commission dated June 6, 2024 in Case No. U-21646

Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 4)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Monthly Rate and revise prices and line losses)

Third Revised Sheet No. D-78.20
Cancels Second Revised Sheet No. D-78.20

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge:	$0.000284	per kWh for all kWh

Power Supply Charges:

Production Charge:

Customer Voltage Level 1	*$10.94*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	*$11.09*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	*$11.26*	per kW of On-Peak Billing Demand for all calendar months

Effective for contracts dated on and after June 7, 2024, the monthly Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution. The monthly Production Charge is fixed for the contract term at the rate in effect at the time of contract execution, unless the customer fails to meet the minimum On-Peak Billing Demand required by the Company. Effective for contracts dated on or before June 7, 2024, customers shall pay the monthly Production Charge which was in effect at the time of contract execution.

Transmission Charge:

Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for either the MISO Real-Time or Day Ahead Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh). Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.

Line losses applied to Energy Charge

Voltage Level 1	*3.23%*
Voltage Level 2	*4.68%*
Voltage Level 3	*6.27%*

(Continued on Sheet No. D-78.30)

Issued June 14, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after June 7, 2024

Issued under authority of the Michigan Public Service Commission dated June 6, 2024 in Case No. U-21646

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Fifth Revised Sheet No. D-78.30
Cancels Fourth Revised Sheet No. D-78.30

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate: (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$0.90	per kW of Maximum Demand
Customer Voltage Level 2:	$3.10	per kW of Maximum Demand
Customer Voltage Level 3:	$5.94	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service Customers.

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.55) per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To modify Maximum Demand and On-Peak Billing Demand)

Second Revised Sheet No. D-78.40
Cancels First Revised Sheet No. D-78.40

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision: (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months. *The contract for service under this rate shall specify the customer's projected Maximum Demand.*

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW. *Upon mutual agreement between the customer and the Company, up to 60 months from the initial service date for billing purposes may be granted for the customer to meet the 35,000 kW On-Peak Billing Demand required to be eligible for this rate.*

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credit (REC) Programs.

(Continued on Sheet No. D-78.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Form of Contract and Authority)

First Revised Sheet No. D-78.50
Cancels Original Sheet No. D-78.50

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Form of Contract *and Authority to Require a Minimum On-Peak Billing Demand by Date Certain*:

Service under this rate shall require a written agreement *between the customer and the Company. The Company may require the customer to meet a minimum On-Peak Billing Demand (in addition to the 35,000 kW required to be eligible for this rate) by a date certain, which shall not exceed the customer's projected Maximum Demand specified in the contract. If the customer fails to meet the minimum On-Peak Billing Demand requirement required by its contract for service under this rate, the customer's Production Charge will be reset at the CONE as of the date certain and annually thereafter for the term of the contract, until the customer meets the required minimum On-Peak Billing Demand, after which the Production Charge will be fixed for the remaining term of the contract.*

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update reference to Rate RSM)

First Revised Sheet No. D-79.00
Cancels Original Sheet No. D-79.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

Availability:

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

First Revised Sheet No. D-80.00
Cancels Original Sheet No. D-80.00

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company:

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company:

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

This program is subject to all general terms and conditions shown on Sheet No. D-1.00.

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

M.P.S.C. No. 14 - Electric
Consumers Energy Company
(To update Administrative Rule)

Second Revised Sheet No. D-81.00
Cancels First Revised Sheet No. D-81.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation with a combined onsite nameplate capacity greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company's electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

"Standby" service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer's generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

"Standby Demand" is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this Rate Schedule.

This rate is not available to Retail Open Access.

Nature of Service

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B., Parallel Operation Requirements. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-Hertz, single-phase or three-phase (as governed by Rule B8., Interconnection and *Distributed Generation* Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 Volts or less but equal to or greater than 2,400 Volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-82.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Real Power Losses, System Access Charge Power Supply Standby Charges and revise prices)

Sixth Revised Sheet No. D-82.00
Cancels Fifth Revised Sheet No. D-82.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of *2.01*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992*%
Customer Voltage Level 2	*1.313*%	*2.239*%
Customer Voltage Level 3	*3.366*%	*6.948*%

Delivery Standby Charges

System Access Charge:	$100.00	per generator installation per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$*5.94*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$*3.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$*0.90*	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-83.00)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-83.00
Cancels Fourth Revised Sheet No. D-83.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(0.55) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

Second Revised Sheet No. D-83.10
Cancels First Revised Sheet No. D-83.10

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit:	$ (0.90)	per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Transmission Interconnect Credit)

Fifth Revised Sheet No. D-84.00
Cancels Fourth Revised Sheet No. D-84.00

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. *D-83.10*)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year. *Service under the Demand Response Program shall require a contract.*

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Demand Response program eligibility language)

First Revised Sheet No. D-84.10
Cancels Original Sheet No. D-84.10

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

Availability:

Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.

The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.

Contracted Capacity and Annual Nominations:

The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.

The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.

At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.

(Continued on Sheet D-84.20)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Rate LTILRR)

Original Sheet No. D-84.20

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.

Monthly Rate:

System Access Charge:	*Fixed charge per billing month as specified in the customer's written agreement for electric service*

Power Supply Charges:

Capacity Charge:	*$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Reserved Capacity Charge:	*$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Excess Capacity Charge:	*$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level*
Interruptible Credit:	*Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge*
Energy Charge:	*The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service*

(Continued on Sheet No. D-84.30)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Interruptible Service Provision)

First Revised Sheet No. D-84.30
Cancels Original Sheet No. D-84.30

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.20)

Power Supply Charges: (Contd)

Excess Energy Charge:	$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges

Transmission Charges:

Transmission Charge:	Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service

Delivery Charges:

Distribution Charges:	Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00

Interruptible Service Provision

The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-84.40)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.30)

Interruptible Service Provision (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.

A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.

General Terms:

The rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-84.50)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To add Rate LTILRR)

Original Sheet No. D-84.50

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.40)

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.

Definitions Applicable to the Long Term Industrial Load Retention Rate:

Annual Forecast Capacity
Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.

Annual Load Factor
Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.

Average Demand
Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.

Capacity Charge
The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.

Energy Charge
The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.

Excess Capacity
The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.

(Continued on Sheet No. D-84.60)

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after January 1, 2021

Issued under authority of the
Michigan Public Service Commission
dated December 17, 2020
in Case No. U-20697

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.50)

Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)

Firm Contracted Capacity

The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.

Interruptible Peak Billing Demand

The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.

Interruptible Service Capacity

Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.

Interval Data Meters

Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.

Maximum Contracted Capacity

The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.

Maximum Monthly Demand

The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.

MISO Planning Year

MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.

Reserved Capacity

The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR

Site

An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fifth Revised Sheet No. D-85.00
Cancels Fourth Revised Sheet No. D-85.00

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.062471*	$0.000000	$*0.062471*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

(Continued on Sheet No. D-86.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Seventh Revised Sheet No. D-86.00
Cancels Sixth Revised Sheet No. D-86.00

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$*0.082650*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.030658*	$0.000000	$*0.030658*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.062986*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11.2., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.2.B., Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

(Continued on Sheet No. D-87.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-87.00

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-86.00)

Monthly Rate (Contd)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule.

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines, supply the energy, control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaries, the Company shall furnish, install and own all equipment comprising the unmetered lighting system. The Company shall supply the energy, and renew and maintain the entire equipment. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be furnished, owned, installed and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company's general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall install new luminaires and associated facilities under this rate, or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.

B. At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest standard size high-pressure sodium luminaire at no cost to the customer. If requirements for installations make it necessary for the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain due to federal or state requirements, the Company shall cover the cost of the bulb and the customer shall be responsible for all other expenses as a contribution. For conversions completed with normal Company maintenance such as replacement of bulbs on a routine schedule or due to failure, then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution. If other light upgrading is also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

   Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.

C. Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company, the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.

D. Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.

E. For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.

F. For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

G. If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.

(Continued on Sheet No. D-90.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.00
Cancels Third Revised Sheet No. D-90.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-89.00)

Monthly Rate

Transitional Rates, effective *March 18, 2022* through June 30, 2022:

The charge per luminaire per month shall be

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)			Service Charge per Luminaire (4)			
Type of Luminaire	Watts	Watts Including Ballast (2)	Lumens	Non-Capacity	Capacity	Total	Fixture Charge per Luminaire (4)
Mercury Vapor (3)	100	128	3,500	$9.72	$0.00	$9.72	$3.00
Mercury Vapor (3)	175	209	7,500	13.28	0.00	13.28	3.00
Mercury Vapor (3)	250	281	10,000	16.45	0.00	16.45	3.00
Mercury Vapor (3)	400	458	20,000	*24.23*	0.00	*24.23*	3.00
Mercury Vapor (3)	700	770	35,000	37.96	0.00	37.96	3.00
Mercury Vapor (3)	1,000	1,080	50,000	*51.59*	0.00	*51.59*	3.00
High-Pressure Sodium (3)	70	83	5,000	7.74	0.00	7.74	3.00
High-Pressure Sodium	100	117	8,500	9.23	0.00	9.23	3.00
High-Pressure Sodium	150	171	14,000	11.61	0.00	11.61	3.00
High-Pressure Sodium (3)	200	247	20,000	*14.96*	0.00	*14.96*	3.00
High-Pressure Sodium	250	318	24,000	*18.07*	0.00	*18.07*	3.00
High-Pressure Sodium	400	480	45,000	*25.20*	0.00	*25.20*	3.00
Fluorescent (3)	380	470	20,000	*24.76*	0.00	*24.76*	3.00
Incandescent (3)	202	202	2,500	*12.98*	0.00	*12.98*	3.00
Incandescent (3)	305	305	4,000	17.51	0.00	17.51	3.00
Incandescent (3)	405	405	6,000	*21.90*	0.00	*21.90*	3.00
Incandescent (3)	690	690	10,000	*34.44*	0.00	*34.44*	3.00
Metal Halide (3)	150	170	9,750	*11.56*	0.00	*11.56*	3.00
Metal Halide (3)	175	210	10,500	13.33	0.00	13.33	3.00
Metal Halide (3)	250	290	15,500	*16.84*	0.00	*16.84*	3.00
Metal Halide (3)	400	460	24,000	24.33	0.00	24.33	3.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *22.6%* Power Supply Charge and a *77.4%* Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 15.6% Power Supply Charge and a 84.4% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-90.10)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered
on and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-90.10
Cancels Second Revised Sheet No. D-90.10

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.41	$0.00	$0.41	$10.39	$10.80
25-34 W	Per Light	$0.62	$0.00	$0.62	$11.02	$11.64
35-44 W	Per Light	$0.84	$0.00	$0.84	$11.64	$12.48
45-54 W	Per Light	$1.05	$0.00	$1.05	$12.27	$13.32
55-64 W	Per Light	$1.26	$0.00	$1.26	$12.90	$14.16
65-74 W	Per Light	$1.47	$0.00	$1.47	$13.52	$14.99
75-84 W	Per Light	$1.68	$0.00	$1.68	$14.15	$15.83
85-94 W	Per Light	$1.89	$0.00	$1.89	$14.77	$16.66
95-104 W	Per Light	$2.10	$0.00	$2.10	$15.40	$17.50
105-114 W	Per Light	$2.32	$0.00	$2.32	$16.03	$18.35
115-124 W	Per Light	$2.53	$0.00	$2.53	$16.65	$19.18
125-134 W	Per Light	$2.74	$0.00	$2.74	$17.28	$20.02
135-144 W	Per Light	$2.95	$0.00	$2.95	$17.90	$20.85
145-154 W	Per Light	$3.16	$0.00	$3.16	$18.53	$21.69
155-164 W	Per Light	$3.37	$0.00	$3.37	$19.16	$22.53
165-174 W	Per Light	$3.59	$0.00	$3.59	$19.78	$23.37
175-184 W	Per Light	$3.80	$0.00	$3.80	$20.41	$24.21
185-194 W	Per Light	$4.01	$0.00	$4.01	$21.03	$25.04
195-204 W	Per Light	$4.22	$0.00	$4.22	$21.66	$25.88
205-214 W	Per Light	$4.43	$0.00	$4.43	$22.29	$26.72
215-224 W	Per Light	$4.64	$0.00	$4.64	$22.91	$27.55
225-234 W	Per Light	$4.85	$0.00	$4.85	$23.54	$28.39
235-244 W	Per Light	$5.07	$0.00	$5.07	$24.17	$29.24
245-254 W	Per Light	$5.28	$0.00	$5.28	$24.79	$30.07
255-264 W	Per Light	$5.49	$0.00	$5.49	$25.42	$30.91
265-274 W	Per Light	$5.70	$0.00	$5.70	$26.04	$31.74
275-284 W	Per Light	$5.91	$0.00	$5.91	$26.67	$32.58
285-294 W	Per Light	$6.12	$0.00	$6.12	$27.30	$33.42
295-304 W	Per Light	$6.34	$0.00	$6.34	$27.92	$34.26
305-314 W	Per Light	$6.55	$0.00	$6.55	$28.55	$35.10
315-324 W	Per Light	$6.76	$0.00	$6.76	$29.17	$35.93
325-334 W	Per Light	$6.97	$0.00	$6.97	$29.80	$36.77
335-344 W	Per Light	$7.18	$0.00	$7.18	$30.43	$37.61
345-354 W	Per Light	$7.39	$0.00	$7.39	$31.05	$38.44
355-364 W	Per Light	$7.60	$0.00	$7.60	$31.68	$39.28
365-374 W	Per Light	$7.82	$0.00	$7.82	$32.30	$40.12
375-384 W	Per Light	$8.03	$0.00	$8.03	$32.93	$40.96
385-394 W	Per Light	$8.24	$0.00	$8.24	$33.56	$41.80
395-404 W	Per Light	$8.45	$0.00	$8.45	$34.18	$42.63
405-414 W	Per Light	$8.66	$0.00	$8.66	$34.81	$43.47
415-424 W	Per Light	$8.87	$0.00	$8.87	$35.44	$44.31
425-434 W	Per Light	$9.09	$0.00	$9.09	$36.06	$45.15
435-444 W	Per Light	$9.30	$0.00	$9.30	$36.69	$45.99
445-454 W	Per Light	$9.51	$0.00	$9.51	$37.31	$46.82
455-464 W	Per Light	$9.72	$0.00	$9.72	$37.94	$47.66
465-474 W	Per Light	$9.93	$0.00	$9.93	$38.57	$48.50
475-484 W	Per Light	$10.14	$0.00	$10.14	$39.19	$49.33

(Continued on Sheet No. D-90.20)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.20
Cancels Third Revised Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-91.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To update Securitization Charges)

Fourth Revised Sheet No. D-91.00
Cancels Third Revised Sheet No. D-91.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.20)

Monthly Rate: (Contd)

Green Generation Program:

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms, Surcharges, Power Supply Cost Recovery (PSCR) Factor and Securitization Charges:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00, Surcharges shown on Nos. D-2.00 through D-5.00, PSCR Factor shown on Sheet No. D-6.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10.*

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

(Continued on Sheet No. D-92.00)

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Streetlighting Outage Credit language)

First Revised Sheet No. D-92.00
Cancels Original Sheet No. D-92.00

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-91.00)

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the capacity requirements in watts of the lamp(s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Rate GU-LED)

First Revised Sheet No. D-93.00
Cancels Original Sheet No. D-93.00

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

Nature of Service:

Company-Owned Option

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:

Company-Owned Option

Following execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company. *A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-94.00)

Issued December 30, 2020 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Company-Owned Conversion Credit)

Fifth Revised Sheet No. D-94.00
Cancels Fourth Revised Sheet No. D-94.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $(8.11) per month

(Continued on Sheet No. D-94.10)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Second Revised Sheet No. D-94.10
Cancels First Revised Sheet No. D-94.10

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.00)

Monthly Rate (Contd)

Transitional Unmetered Lighting Rate GU-LED Charges, effective *March 18, 2022* through June 30, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$8.32	$8.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$8.98	$9.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$9.64	$10.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$10.31	$11.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$10.97	$12.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$11.63	$12.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$12.30	$13.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$12.96	$14.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$13.62	$15.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$14.28	$16.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$14.95	$17.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$15.61	$17.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$16.27	$18.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$16.94	$19.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$17.60	$20.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$18.26	$21.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$18.93	$22.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$19.59	$22.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$20.25	$23.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$20.92	$24.51

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	$5.32	$5.66
25-34 W	Per Light	$0.51	$0.00	$0.51	$5.98	$6.49
35-44 W	Per Light	$0.68	$0.00	$0.68	$6.64	$7.32
45-54 W	Per Light	$0.86	$0.00	$0.86	$7.31	$8.17
55-64 W	Per Light	$1.03	$0.00	$1.03	$7.97	$9.00
65-74 W	Per Light	$1.20	$0.00	$1.20	$8.63	$9.83
75-84 W	Per Light	$1.37	$0.00	$1.37	$9.30	$10.67
85-94 W	Per Light	$1.54	$0.00	$1.54	$9.96	$11.50
95-104 W	Per Light	$1.71	$0.00	$1.71	$10.62	$12.33
105-114 W	Per Light	$1.88	$0.00	$1.88	$11.28	$13.16
115-124 W	Per Light	$2.05	$0.00	$2.05	$11.95	$14.00
125-134 W	Per Light	$2.23	$0.00	$2.23	$12.61	$14.84
135-144 W	Per Light	$2.40	$0.00	$2.40	$13.27	$15.67
145-154 W	Per Light	$2.57	$0.00	$2.57	$13.94	$16.51
155-164 W	Per Light	$2.74	$0.00	$2.74	$14.60	$17.34
165-174 W	Per Light	$2.91	$0.00	$2.91	$15.26	$18.17
175-184 W	Per Light	$3.08	$0.00	$3.08	$15.93	$19.01
185-194 W	Per Light	$3.25	$0.00	$3.25	$16.59	$19.84
195-204 W	Per Light	$3.42	$0.00	$3.42	$17.25	$20.67
205-214 W	Per Light	$3.59	$0.00	$3.59	$17.92	$21.51

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-94.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Third Revised Sheet No. D-94.20
Cancels Second Revised Sheet No. D-94.20

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.41	$0.00	$0.41	$10.39	$10.80
25-34 W	Per Light	$0.62	$0.00	$0.62	$11.02	$11.64
35-44 W	Per Light	$0.84	$0.00	$0.84	$11.64	$12.48
45-54 W	Per Light	$1.05	$0.00	$1.05	$12.27	$13.32
55-64 W	Per Light	$1.26	$0.00	$1.26	$12.90	$14.16
65-74 W	Per Light	$1.47	$0.00	$1.47	$13.52	$14.99
75-84 W	Per Light	$1.68	$0.00	$1.68	$14.15	$15.83
85-94 W	Per Light	$1.89	$0.00	$1.89	$14.77	$16.66
95-104 W	Per Light	$2.10	$0.00	$2.10	$15.40	$17.50
105-114 W	Per Light	$2.32	$0.00	$2.32	$16.03	$18.35
115-124 W	Per Light	$2.53	$0.00	$2.53	$16.65	$19.18
125-134 W	Per Light	$2.74	$0.00	$2.74	$17.28	$20.02
135-144 W	Per Light	$2.95	$0.00	$2.95	$17.90	$20.85
145-154 W	Per Light	$3.16	$0.00	$3.16	$18.53	$21.69
155-164 W	Per Light	$3.37	$0.00	$3.37	$19.16	$22.53
165-174 W	Per Light	$3.59	$0.00	$3.59	$19.78	$23.37
175-184 W	Per Light	$3.80	$0.00	$3.80	$20.41	$24.21
185-194 W	Per Light	$4.01	$0.00	$4.01	$21.03	$25.04
195-204 W	Per Light	$4.22	$0.00	$4.22	$21.66	$25.88
205-214 W	Per Light	$4.43	$0.00	$4.43	$22.29	$26.72
215-224 W	Per Light	$4.64	$0.00	$4.64	$22.91	$27.55
225-234 W	Per Light	$4.85	$0.00	$4.85	$23.54	$28.39
235-244 W	Per Light	$5.07	$0.00	$5.07	$24.17	$29.24
245-254 W	Per Light	$5.28	$0.00	$5.28	$24.79	$30.07
255-264 W	Per Light	$5.49	$0.00	$5.49	$25.42	$30.91
265-274 W	Per Light	$5.70	$0.00	$5.70	$26.04	$31.74
275-284 W	Per Light	$5.91	$0.00	$5.91	$26.67	$32.58
285-294 W	Per Light	$6.12	$0.00	$6.12	$27.30	$33.42
295-304 W	Per Light	$6.34	$0.00	$6.34	$27.92	$34.26
305-314 W	Per Light	$6.55	$0.00	$6.55	$28.55	$35.10
315-324 W	Per Light	$6.76	$0.00	$6.76	$29.17	$35.93
325-334 W	Per Light	$6.97	$0.00	$6.97	$29.80	$36.77
335-344 W	Per Light	$7.18	$0.00	$7.18	$30.43	$37.61
345-354 W	Per Light	$7.39	$0.00	$7.39	$31.05	$38.44
355-364 W	Per Light	$7.60	$0.00	$7.60	$31.68	$39.28
365-374 W	Per Light	$7.82	$0.00	$7.82	$32.30	$40.12
375-384 W	Per Light	$8.03	$0.00	$8.03	$32.93	$40.96
385-394 W	Per Light	$8.24	$0.00	$8.24	$33.56	$41.80
395-404 W	Per Light	$8.45	$0.00	$8.45	$34.18	$42.63
405-414 W	Per Light	$8.66	$0.00	$8.66	$34.81	$43.47
415-424 W	Per Light	$8.87	$0.00	$8.87	$35.44	$44.31
425-434 W	Per Light	$9.09	$0.00	$9.09	$36.06	$45.15
435-444 W	Per Light	$9.30	$0.00	$9.30	$36.69	$45.99
445-454 W	Per Light	$9.51	$0.00	$9.51	$37.31	$46.82
455-464 W	Per Light	$9.72	$0.00	$9.72	$37.94	$47.66
465-474 W	Per Light	$9.93	$0.00	$9.93	$38.57	$48.50
475-484 W	Per Light	$10.14	$0.00	$10.14	$39.19	$49.33

(Continued on Sheet No. D-94.30)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-94.30
Cancels Third Revised Sheet No. D-94.30

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-95.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise Streetlighting Outage Credit language)

Fourth Revised Sheet No. D-95.00
Cancels Third Revised Sheet No. D-95.00

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.30)

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered LED Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered LED Lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise rates)

Sixth Revised Sheet No. D-96.00
Cancels Fifth Revised Sheet No. D-96.00

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$0.074181	*$0.002717*	*$0.076898*	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	*$0.026586*	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10.

(Continued on Sheet No. D-97.00)

Issued March 22, 2024 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on and after March 15, 2024

Issued under authority of the Michigan Public Service Commission dated March 1, 2024 in Case No. U-21389

M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To reformat Rate Book)

Original Sheet No. D-97.00

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-96.00)

Monthly Rate: (Contd)

Determination of kWh:

The monthly charge shall be the per kWh total of the Power Supply and Delivery Charges as shown above based on the capacity requirements in Kilowatts of the lamp(s), associated ballast(s) and control equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption. At the Company's option, such service may be metered and the metered kWh used as the basis for billing. The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

For dusk to midnight service for energy-only unmetered lighting, the monthly charge per kWh shall be 130% of the sum of the Secondary Energy Charge and Distribution Charge per kWh for secondary service. The annual kWh shall be based on the actual burning hours. The monthly kWh for billing shall be the annual kWh adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be 50% of the total kWh so calculated. The kWh for continuous, nonintermittent devices shall be 100% of the total kWh so calculated. No reduction in kWh shall be made for devices not operated 24 hours per day, or not operated every day.

The kWh of devices used for the control of school traffic, and operated not more than six hours per day during the school year only, shall be 10% of the continuous or cyclical kWh calculated.

The kWh for CATV Power Supply Units shall be 50% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The kWh for Wireless Access and Security Camera Power Supply Units shall be 100% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The Company may, at its option, install test meters for the purpose of determining the monthly kWh usage to be used for billing purposes.

(Continued on Sheet No. D-98.00)

Issued December 13, 2019 by
Patti Poppe,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after November 15, 2019

Issued under authority of the
Michigan Public Service Commission
dated November 14, 2019
in Case No. U-18249

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-97.00)

Monthly Rate (Contd)

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

These programs provide customers with the opportunity to subscribe to the environmental attribute of renewable energy by offering customers the ability to utilize renewable energy credits to match up to 100% of their total annual energy.

A customer that participates in one of the Renewable Energy Credit (REC) Programs is subject to the provisions contained in Rule C10.7., Renewable Energy Credits (REC) Programs.

General Terms

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Minimum Charge

The System Access Charge included in the rate, plus any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

Designees for Copies of Contracts

The Company designates a primary and secondary contact to assist with requested customer contract review. The designated contacts are:

Primary Designee:

Name: Sarah Jorgensen
Email: sarah.jorgensen@cmsenergy.com
Office Phone: (517) 788-2349

Secondary Designee:

Name: Natalie Busack
Email: NATALIE.BUSACK@cmsenergy.com
Office Phone: (517) 788-0931

Attachment JJ

Jester Affidavit Signed September 8, 2025

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-7

AFFIDAVIT OF DOUGLAS JESTER

Douglas Jester states that the following information is true and accurate to the best of my knowledge and belief:

1. I am the Managing Partner of 5 Lakes Energy, a clean-energy consulting firm. Previously, I served in various roles in Michigan state government and in the private sector. I began my career in ecosystem modeling, working for the State of Michigan from 1977 to 1999. In 2011, I cofounded 5 Lakes Energy.
2. I have a masters degree in statistics from Virginia Polytechnic Institute & State University and completed coursework for a Ph.D. in Environmental Economics from Michigan State University. I am a frequent expert witness before the Michigan Public Service Commission (MPSC).
3. I have used the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) regularly in my work, in part because the MPSC requires utilities in Michigan to use the COBRA tool to develop integrated resource plans.
4. The COBRA tool is a web-based model developed and maintained by the U.S. Environmental Protection Agency (EPA) to model the co-benefits of reductions in greenhouse gasses.[1] Those co-benefits are the benefits to public health due to reductions in co-pollutants, namely $PM_{2.5}$, NOx, SO_2, and VOCs.
5. The COBRA tool allows for the modeling of health impacts over time, based on emissions over a particular year. The model allows a user to specify

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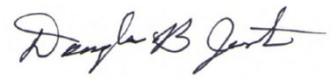
[1] *See* U.S. EPA, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), Version: 5.2 (March 2025), *https://www.epa.gov/system/files/documents/2025-03/cobra-user-manual-v5.2.pdf*

particular scenarios of emission controls. It is available at: https://cobra.epa.gov/.

6. To estimate the health impacts of running the J.H. Campbell Plant during the pendency of the Extension Order, I used the COBRA tool as follows.
7. I first selected the relevant county in Michigan—Ottawa County.
8. I then identified the relevant sector—Fuel Combustion: Electric Utility—and subsector—Coal.
9. I am aware that the J.H. Campbell plant is the only coal-fired power plant in Ottawa County.
10. I then selected a 100% reduction in each of the relevant pollutants.
11. Together, these parameters reflect the closure of the J.H. Campbell plant.
12. Finally, I selected a discount rate—2%.
13. The resulting figures provide an estimate for the health benefits over time of a year's worth of emissions reductions from the closure of the J.H. Campbell plant.
14. These figures also provide an estimate of the health harms resulting from the continued operation of the J.H. Campbell plant.
15. According to the COBRA tool, those harms in all contiguous U.S. states include 27-36 excess deaths, as well as thousands of lost school and work days. In total, the COBRA tool estimates that the total monetized value of health effects are $420 million to $700 million in 2023 dollars.
16. I also filtered the results of the model to show health effects in Michigan only. For Michigan alone, the COBRA model estimates 8.1 - 13 excess deaths and monetized health effects of $130 million to $200 million.
17. These estimates of public-health benefits produced by the COBRA tool are based on closing the J.H. Campbell plant for a year.
18. I understand that the Extension Order prevents the J.H. Campbell plant from closing from August 21, 2025, to November 19, 2025.
19. As a rough approximation, the benefits from closing the plant for the three-month period of the Extension Order would be one quarter the benefits of a year-long closure.
20. To precisely estimate the harm from the continued operation of the J.H. Campbell plant, one would need to know, or model, which generation resources are displaced by its operation. Such precision is unrealistic. But it is almost certainly true that most of the generation displaced by the continued operation of J.H. Campbell comes from natural gas combined cycle plants.

21. The health impacts from running those plants vary depending on location, time of year, and the specific technologies employed by the plant, but they are invariably less than coal.
22. Accordingly, I can conclude that the continued operation of the J.H. Campbell plant will have a net harmful effect on public health in Michigan.



Douglas Jester