Attachment D

Consumers' Responses from June 10, 2025

Question:

23. Absent continued operation of the Campbell Plant, what was Consumers Energy's Zone Resource Credit (ZRC) position for planning year 2025-2026.

Response:

The table below shows our capacity positions using the initial Planning Reserve Margin Requirement (PRMR) for each season of planning year 2025. These numbers do not include any contributions from the Campbell coal-fired generating units.

PY2025	**ZRC**
Summer	272.9
Fall	842.7
Winter	0.0
Spring	4.3

Date: June 10, 2025

Question:

24. How many ZRCs does Consumers anticipate will be accredited for the continued operation of the Campbell Plant?

Response:

At this time we do not anticipate the Campbell units contributing any Zonal Resource Credits to our capacity positions throughout planning year 2025.

Date: June 10, 2025

Attachment DD

FERC, Security Constrained Economic Dispatch
(July 31, 2006)

SECURITY CONSTRAINED ECONOMIC DISPATCH: DEFINITION, PRACTICES, ISSUES AND RECOMMENDATIONS

A Report to Congress
Regarding the Recommendations of Regional Joint Boards
For The Study of Economic Dispatch
Pursuant to Section 223 of the Federal Power Act
As Added by Section 1298 of the Energy Policy Act of 2005

Federal Energy Regulatory Commission
July 31, 2006

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EXECUTIVE SUMMARY

Section 1298 of the Energy Policy Act of 2005[1] (EPAct 2005) added new section 223, "Joint Boards on Economic Dispatch," to the Federal Power Act (FPA).[2] Section 223 requires the Federal Energy Regulatory Commission (Commission) to convene joint boards on a regional basis pursuant to FPA section 209 [3] "to study the issue of security constrained economic dispatch for the various market regions," "to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating . . . affects or enhances the reliability and affordability of service to customers in the region concerned, and "to make recommendations to the Commission regarding such issues." Section 223 requires the Commission to designate appropriate regions to be covered by each joint board, to request each state to nominate a representative for the appropriate regional joint board, and to designate a member of the Commission to chair and participate as a member of each joint board. It also directs the Commission to issue a report to Congress regarding the recommendations of the joint boards within one year of enactment of EPAct 2005. This report is submitted in response to section 223's directives.

The Commission designated four market regions for the joint boards, established the joint boards, designated a Commissioner to chair each board, and requested each state to nominate a board representative to the appropriate joint board. The four joint board regions are: PJM-MISO (consisting of the states of Delaware, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia, Wisconsin, and the District of Columbia); Northeast (consisting of the states of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont); South (consisting of the states of Alabama, Arkansas, Florida, Georgia, Kansas, Louisiana, Mississippi, Missouri, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, and Texas); and West (consisting of the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming).

The joint boards convened for two public meetings. Each regional joint board developed a specific set of issues for its region from material provided at public meetings or submitted in writing later. The boards then formulated recommendations regarding these issues and submitted reports to the Commission. The boards' recommendations

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[1] Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005) (to be codified at 16 U.S.C. § 824).

[2] 16 U.S.C. §§ 824 *et seq.* (2000).

[3] 16 U.S.C. § 824h (2000); *see* 18 C.F.R. §§ 385.1301-.1306 (2005).

were presented to the Commission at the Commission's July 20, 2006 public meeting.

None of the joint boards recommends fundamental changes in the way security constrained economic dispatch (SCED) is conducted in their respective regions. For example, regions where centralized dispatch predominates (PJM-MISO and the Northeast) do not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (the South and the West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing regional transmission organizations (RTOs) that dispatch the system on a centralized basis (PJM-MISO and the Northeast), there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for broad changes. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis.

Joint board recommendations reflected a variety of responses to the issues. There were no recommendations for Congressional action and only a few recommendations for the Commission. For example, the Northeast joint board recommends that the New York ISO and ISO New England work together to resolve trading seams issues and file a plan and timeline with the Commission. That board also recommends that the Commission request the ISO-RTO Council to identify best dispatch practices to guide future improvements in dispatch tools. As part of its investigation of dispatch practices, the Department of Energy (DOE) recommends that the Commission and DOE explore proposals for standard terms in the contracts between generators and dispatchers regarding placing and accepting supply offers, operating requirements, and non-performance penalties. [4]

Most joint board proposals calling for some form of action were directed to existing entities within the region, such as RTOs, other regional groups or state commissions. The major issues addressed by the boards are the geographic scope of the dispatch, transparency of dispatching and pricing information, independence of the dispatcher from market interests, and demand response. The joint boards also addressed the pertinent recommendations made in the DOE Report. Most of the joint board recommendations are discussed in the body of this report and are described in detail in the reports of the joint boards, included as appendices to this report.

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[4] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005 (DOE Report) at p. 51..

I. INTRODUCTION

Section 1298 of the Energy Policy Act of 2005[5] adds new section 223, "Joint Boards on Economic Dispatch," to the Federal Power Act (FPA).[6]
New FPA section 223 states:

> (a) In General- The Commission shall convene joint boards on a regional basis pursuant to section 209 of this Act to study the issue of security constrained economic dispatch for the various market regions. The Commission shall designate the appropriate regions to be covered by each such joint board for purposes of this section.
> (b) Membership- The Commission shall request each State to nominate a representative for the appropriate regional joint board, and shall designate a member of the Commission to chair and participate as a member of each such board.
> (c) Powers- The sole authority of each joint board convened under this section shall be to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.
> (d) Report to the Congress- Within one year after enactment of this section, the Commission shall issue a report and submit such report to the Congress regarding the recommendations of the joint boards under this section and the Commission may consolidate the recommendations of more than one such regional joint board, including any consensus recommendations for statutory or regulatory reform.

This report is submitted in response to section 223's directives. The report is organized as follows. This section summarizes the statutory basis for the report and the process followed in convening the joint boards. The second section, *Security Constrained Economic Dispatch: Concept and Regional Application* provides the definition of Security Constrained Economic Dispatch (SCED) used in this report and summarizes the four regional board reports describing how SCED is practiced in each joint board region. The third section, *Review of Joint Board Issues and Recommendations,* presents a synopsis of the issues considered and the recommendations made by each board.

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[5] Pub. L. No. 109-58, § 1298, 119 Stat. 594, 986 (2005) (to be codified at 16 U.S.C. § 824).

[6] 16 U.S.C. §§ 824 *et seq.* (2000).

Process for Convening Joint Boards

On September 30, 2005, the Commission issued an order convening joint boards in the following four regions: the Northeast, Pennsylvania-New Jersey- Maryland and the Midwest Independent Transmission Operator (PJM-MISO), the West, and the South.[7] A FERC Commissioner was designated to chair each board; and states were requested to nominate a board representative to the appropriate joint board. Further, the Commission announced that it planned to hold the first meetings of the joint boards in the month of November 2005, if not earlier. Representatives from Canada and Mexico were also invited to participate, as observers, on the appropriate joint boards.

The Northeast Joint Board comprises the states covered by the New York ISO (NYISO) and ISO-New England (ISO-NE): Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. The PJM-MISO Joint Board comprises the states served primarily by the PJM RTO and the Midwest ISO (MISO): Delaware, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Virginia, West Virginia, Wisconsin, and the District of Columbia. The West Joint Board includes all the states in the Western Interconnection: Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming. Finally, the South Joint Board includes Alabama, Arkansas, Florida, Georgia, Kansas, Louisiana, Mississippi, Missouri, New Mexico, North Carolina, Oklahoma, South Carolina, Tennessee, and Texas. The Commission recognized that some states have utilities in more than one delineated market area, and permitted these states to have representatives on more than one joint board.

FERC Chairman Joseph T. Kelliher chaired the South board; Commissioner Nora Mead Brownell chaired the Northeast and PJM-MISO boards; and Commissioner Suedeen G. Kelly chaired the West board. Upon receiving nominations for each joint board member, the Commission issued a notice listing the members on October 21, 2005.[8] In addition, one or two Vice Chairs were selected for each board. Table 1 shows the Chair, the Vice-Chair(s) and the member states on each board. The names of all members of the joint boards are listed in Appendix A of this report.

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[7] *Joint Boards on Security Constrained Economic Dispatch*, 112 FERC ¶ 61,353 (2005). The Commission established the joint boards in Docket No. AD05-13-000, where all orders, notices and filings in this proceeding are available.

[8] These members changed over time and the Commission staff maintained an updated list on its website at http://www.ferc.gov/industries/electric/indus-act/joint-boards.asp. This webpage also provided additional details on this proceeding.

The joint boards convened for two public meetings, in November 2005 and February 2006. The initial meetings of the West and South Joint Boards were held on November 13, 2005 in California. The initial PJM-MISO Joint Board meeting was held in Illinois on November 21, 2005. Finally, the initial Northeast Joint Board meeting was held in Massachusetts on November 29, 2005. The notices announcing the agenda and participants at each of the meetings are included as Appendix B.[9]

Upon the conclusion of the initial meetings, the Chairs of each joint board instructed Commission staff to draft a list of recommendations gleaned from the discussion and presentations at each of the meetings. Commission staff then circulated the list for each region to the joint board members for their comment. In addition, various comments were filed with the Commission after the meetings and placed in the public record.

On January 6, 2006, the Commission announced that it would convene follow-up meetings in Washington, D.C. on February 12-13, 2006 to further discuss the draft list of recommendations. In addition, the joint board members discussed preparation and completion of their respective studies and recommendations to the Commission.

The final reports from each board were filed with the Commission in May and July 2006 and are included as Appendices to this report. The boards' recommendations were presented to the Commission at the Commission's July 20, 2006 public meeting. The boards' reports and recommendations draw on the discussions at the joint board meetings, contributions of members of each board and their staffs, and other materials provided to each board during the course of the study. Each board also considered a report on economic dispatch completed by the Department of Energy (DOE)[10] pursuant to the Section 1234 of Energy Policy Act of 2005. This section directs DOE, in consultation and coordination with the states, to study economic dispatch, including the ability of non-utility generation resources to offer their output for inclusion in economic dispatch, and to report to Congress within 90 days, *i.e.*, by November 7, 2005. [11]

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[9] The notices and the transcripts of the meetings are also available on the Commission's website, in eLibrary under Docket No. AD05-13-000.

[10] United States Department of Energy, *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005* (2005)(DOE Report).

[11] Pub. L. No. 109-58, § 1234, 119 Stat. 594, 960 (2005.

Table 1: Chair, Vice Chair(s) and Member States of Regional Joint Boards				
	Regional Board			
	Northeast	**PJM-MISO**	**South**	**West**
Chair	Commissioner Nora Mead Brownell	Commissioner Nora Mead Brownell	Chairman Joseph T. Kelliher	Commissioner Suedeen G. Kelly
Vice Chair(s)	Commissioner Paul G. Alfonso, Massachusetts; Chairman William M. Flynn, New York	Commissioner Kevin K. Wright, Illinois; Commissioner Kenneth D. Schisler, Maryland	Commissioner Sam J. Ervin IV, North Carolina	Commissioner Marsha H. Smith, Idaho
Member States	Connecticut Maine Massachusetts New Hampshire New York Rhode Island Vermont	Delaware District of Columbia Illinois Indiana Iowa Kentucky Maryland Michigan Minnesota Missouri Montana Nebraska, New Jersey North Carolina North Dakota Ohio Pennsylvania South Dakota Virginia West Virginia Wisconsin	Alabama, Arkansas Florida Georgia Kansas Louisiana Mississippi Missouri New Mexico North Carolina Oklahoma South Carolina Tennessee Texas	Arizona California Colorado Idaho Montana Nevada New Mexico Oregon South Dakota Texas Utah Washington Wyoming

II. SECURITY CONSTRAINED ECONOMIC DISPATCH: CONCEPT AND REGIONAL APPLICATION

Before identifying the joint boards' issues and recommendations regarding security constrained economic dispatch, or SCED, it is important to define what is meant by SCED and to describe the way it is implemented in the regions. For purposes of the four regional joint boards' studies, the Commission adopted the definition of SCED from Section 1234 of EPAct 2005: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[12] This definition describes the basic way utilities dispatch their own and purchased resources to meet electricity load. All four joint boards generally agreed with this definition and with the basic process for implementing SCED.

The next sections describe the basic SCED process, and then generally describe how that process is carried out in the four regions. More detailed descriptions of how SCED is carried out in the regions may be found in the joint board final reports.

The Basic Concept of Security Constrained Economic Dispatch

There are a number of unique challenges to supplying electricity: production must be simultaneous with demand; demand varies greatly over the course of a day, week, and season; the costs of different types of generating units vary greatly; and expected and unexpected conditions on the transmission network affect which generating units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch, in order to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

There are two stages, or time periods, to the economic dispatch process: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum

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[12] *Joint Boards on Security Constrained Economic Dispatch*, 112 FERC ¶ 61,353 at P14 (2005).

output levels, and the minimum time a generator must run once it is started. Operators must also take into account generating unit costs, such as fuel and non-fuel operating costs and costs of environmental compliance.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security constrained" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that reliability is maintained and overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load.

Implementation of Security Constrained Economic Dispatch in the Joint Board Regions

The basic ways that SCED is implemented in the joint board regions may be thought of as falling into two categories. The first way of implementing SCED is having the dispatch performed by individual utilities or holding companies, primarily with their own generation, or other generation directly under their control. Generation is dispatched based on the costs of operating each generating unit. Dispatch in the South and West regions is generally, although not exclusively, done this way. The second way of implementing SCED is having the dispatch performed on a market basis by an independent entity for all resources across a region. Generators are selected for dispatch based on their supply offer bids into day-ahead and real-time markets. The level of dispatch may also be affected by bids by demand side resources. Locational marginal prices (LMP) result from the dispatch. Dispatch in the Northeast and the PJM-MISO regions is done this way.

Of course, actual dispatch practices in the regions reflect differences in regional characteristics and preferences. The rest of this section summarizes the way SCED is actually implemented in the regions *as described in the joint board reports.*

West

Dispatch in the West is primarily accomplished by individual utilities, but with a number of coordination arrangements to address specific resource characteristics and trading opportunities. The presence of significant hydropower resources in the Northwest makes Western Interconnection generation dispatch significantly different from dispatch in the Eastern Interconnection. The West also has a long history of coordination in the Northwest aimed at optimizing power and non-power river demands. Another factor affecting Northwest dispatch is the operation of Bonneville Power Authority transmission assets, which are closely connected to the operation of hydropower resources. Although the presence of significant hydropower resources in the Northwest affects the overall operation and dispatch of the system, the basic dispatch remains decentralized.

The California ISO (CAISO) is the only multi-utility market area in the West that is centrally organized and dispatched. The CAISO performs a dispatch covering most of California by using market bids to balance generation and load.

The overall pattern of dispatch in the West also depends to a large extent on differences between the resources and loads in each subregion. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flows from south to north to meet the peak loads in the Northwest. A north-south transmission system has developed to support this pattern. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west in California and the Northwest. The transmission systems also reflect the need to move power westward from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

South

The practice of economic dispatch in the South varies by utility and subregion. In most of the South, economic dispatch is performed on a system-by-system basis. Some utilities in the region dispatch across large multi-state areas. For example, Entergy is a collection of utilities in a holding company, and dispatches for its operating companies in Arkansas, Louisiana, Mississippi, and Texas from its own generation resources and purchases from non-utility generators. Similarly, Southern Company dispatches for its footprint in Alabama, Georgia, and Mississippi using the generation resources of its operating companies and purchases from non-utility generators and other market participants.

Economic dispatch in the Florida Reliability Coordinating Council is performed by eleven Balancing Authorities, (formerly referred to as control areas) through their own economic dispatch energy management system. One balancing authority in the region also acts as a "power pool" for its members. Balancing authority resources are supplemented by wholesale market purchases.

The Electric Reliability Council of Texas (ERCOT) is the only organized market in the South region, consisting of a single area organized out of 10 control areas. In ERCOT there are two entities responsible for the dispatch of the system: qualified scheduling entities (QSEs) and ERCOT.[13] QSEs perform the commitment and dispatch processes by taking into account their portfolios and any other offers on the bilateral markets. ERCOT will then modify or supplement that dispatch to meet total system load, maintain system frequency and manage transmission congestion if necessary. ERCOT administers a balancing energy market which allows all generation, regardless of ownership, to bid and provide balancing energy. ERCOT manages transmission congestion with zonal and intra-zonal arrangements.

Members of the Southwest Power Pool (SPP) are planning to implement an energy imbalance market within the SPP footprint. SPP will perform a real-time security constrained economic dispatch of the entire market footprint. Currently, however, economic dispatch is performed individually by multiple control areas located in the SPP footprint. Each owner of generation performs its own economic dispatch using its own portfolio of resources including generation, purchases and sales, and demand side management.

PJM-MISO

PJM and MISO each implement SCED using a regional, market-based approach. The dispatch is based on supply offers from generators within each RTO to sell energy, along with non-price responsive load needs and price responsive bids to purchase energy. Each RTO considers the resources owned/operated by their respective market participants and then each evaluates its respective market sellers' offers as a single resource pool. The regional resources available to the RTO result in a dispatch stack containing generators from all generation-owning members of the RTO region, including utility and non-utility generation owners, as well as some generation resources outside the RTO.

The dispatch results in a locational marginal price, or LMP, at each location, defined as the marginal cost of serving the next increment of load at the location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. If there are no transmission constraints, LMPs will generally not vary significantly across the RTO

[13] Transcript of the first South Joint Board Meeting, November 13, 2005, Palm Springs, CA, at 63.

region. When there are transmission constraints, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will generally set the LMP in that area. All sellers in the area receive the clearing price for energy and all buyers pay the clearing price in the area.

PJM and MISO have a Joint Operating Agreement (JOA) to closely coordinate their operations. Generally, the JOA facilitates administration of coordinated markets, permitting more efficient and reliable system operation, and would allow additional utilities to integrate more easily into the PJM and MISO markets. The JOA contemplates that the RTOs will progressively integrate their operations.

Northeast

SCED in the Northeast is performed by two organizations, ISO-NE and NYISO. ISO-NE and NYISO each implement SCED using a regional, market-based approach, similar to the approach described for PJM-MISO above. Both entities operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described earlier. There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Long Island, Boston and Southwest Connecticut, that require the dispatch of higher cost local generation.

III. REVIEW OF JOINT BOARD ISSUES AND RECOMMENDATIONS

Each regional joint board developed a specific set of issues for its region from material provided at public meetings or submitted separately. Principal sources included the DOE Report, suggested discussion topics proposed by Commission staff for public discussion, and input from states and industry participants in each region. A set of issues was developed at the first meeting of each board, and formed the starting point for subsequent board discussion and recommendations.

Although there was considerable discussion of the issues surrounding SCED and its impact on customers, none of the joint boards recommends fundamental changes in the way SCED is conducted in their respective regions. For example, regions where centralized dispatch predominates (PJM-MISO, Northeast) did not propose changing the basic dispatch or pricing mechanisms, and regions where individual utility dispatch predominates (South, West) did not propose new initiatives for greater centralization of the dispatch. In regions with existing RTOs, there were a number of recommendations for specific improvements within the existing centralized dispatch framework, but no new proposals for fundamental changes in the way the RTOs operate the dispatch. In regions where individual utility dispatch predominates, the boards were open to voluntary changes to aspects of the existing dispatch, or continued industry pursuit of regional dispatch on a voluntary basis, as long as these initiatives could be demonstrated to provide benefits to customers and gain appropriate state and federal approvals. However, these boards did not call for any specific initiatives and opposed any form of mandated modification.

Joint board recommendations reflect a variety of responses to the issues, including recommending no action (or no immediate action) on a particular issue, simply encouraging continuing activities by industry, endorsing particular outcomes without specific recommendations for action by any group, and proposing actions to achieve a particular result. Most proposals calling for some form of action are directed to existing entities within the region, such as RTOs, other regional groups or state commissions. There are no recommendations for Congressional action and only a few recommendations for Commission involvement, generally to encourage or facilitate activity.

The most widely addressed issues and associated recommendations are discussed in the remainder of this section.[14] Although the specific formulation of any given issue

[14] This section describes the principal joint board recommendations and related issues. The more detailed issues discussed, and recommendations made, can be found in

varied across regions, due to the different characteristics of SCED as implemented in the regions, there are general issues that arise in more than one region. For purposes of this section, these issues are organized as follows:

- Broadening the geographic scope, through consolidation of areas or reduction of seams between areas
- Transparency of dispatching or pricing information
- Independence of the dispatcher
- Including demand response and other factors in the dispatch
- Recommendations from the DOE Report

In addition, some topics received significant discussion in only one region. These topics are also discussed in this section. Further details on recommendations can be found in the individual board reports.

Broadening the Geographic Scope of Dispatch

This issue is a common point of discussion in all four regions, but the nature of the discussion depended on the current regional dispatch practices. In some cases, it takes the form of consolidation or merging of areas, in others, improvement in seams management (i.e., better coordination of dispatch across areas without explicit merging of the dispatch). Although many board members agree, in theory, with the principle that dispatch over a wider geographic range of resources should result in lower costs to produce power, there is also recognition of the practical impediments to achieving this objective, and there are no consensus recommendations across regions on how to proceed. Nevertheless, several regions recommend further study, or encourage the continuation of existing work.

In the Northeast, broadening of the dispatch was focused on two types of "seams," the first being coordination between the two RTOs in the region (ISO-NE and NYISO), and the second being coordination with external areas. For the first issue, the Northeast Joint Board recommends "that both NYISO and ISO-NE work together and with the market participants towards the development of mechanisms to address the specific seams issues,"[15] and "meet within 90 days to coordinate their initiatives and file a plan

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Appendices to this report, containing each of the joint board reports filed with the Commission. The Appendices also note minority viewpoints and contain some individual board members' alternative perspectives as appendices or attachments.

[15] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the Northeast Region* (Northeast Report), May 24, 2006, p. 14.

with FERC describing the time line to address the seams discussed in this section."[16] Regarding coordination with external areas, the board recommends a technical evaluation of electrical connections with those areas to identify potential operating adjustments and system upgrades, and a market impact analysis to determine whether the identified improvements would provide net benefits.

The PJM-MISO Joint Board recommendation on broadening the dispatch encourages continued timely analyses of the cost and technical feasibility of expanding the geographic scope of SCED. The board recommends that the analysis encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO was encouraged to analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO-managed SCED. However, the board emphasized that actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.[17] The PJM-MISO Joint Board also recommends improvements in seams coordination under both the current JOA between PJM and MISO and also under common market proposals being developed by the two RTOs.[18]

The West Joint Board recognized the potential for improved dispatch through consolidation in some subregions in the Western Interconnection, and the potential for improving coordination of dispatch between control areas within the hour. The board recommends studies to assess the value of larger control areas for improving the dispatch of renewables such as wind, and studies to address the problems of large control areas scheduling imports and exports within the hour.[19]

The South Joint Board viewed proposals presented for broadening the scope of dispatch as requiring an RTO or independent third party, and the South Joint Board members "do not recommend that an expanded regional dispatch should be involuntarily implemented in the South at this time."[20]

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[16] *Id.*

[17] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the PJM-MISO Region* (PJM-MISO Report), May 24, 2006, p. 38.

[18] Id.

[19] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the West Region* (West Report), May 12, 2006, p. iii.

[20] *Study and Recommendations Regarding Security Constrained Economic Dispatch by The Joint Board for the South Region* (South Report), July ??, 2006, p. 11.

Transparency and Access to Information

In discussions of this issue at the joint board meetings, transparency generally connoted the ability of market participants to see the price at which electricity was sold or purchased, and to have access to sufficient information to be able to determine under what terms the electricity was being sold and how the price was established. Since SCED is implemented in different ways in each region, and sometimes even within a region, this general theme gave rise to different concerns and different recommendations in each region.

In the Northeast, transparency is viewed in terms of the ability to see how the price was determined from the bids submitted, so that the issue is framed in terms of access to the bid data. The Northeast Joint Board recommends the RTOs pursue making bid data available to the market with a shorter lag time.[21]

In PJM-MISO, the issue of transparency of the RTO spot price was referenced as a benefit of the organized market,[22] and there was discussion of the importance of the transparency provided by the organized market process,[23] but there were no recommendations regarding changes in release of bid information or other measures to enhance transparency. There were concerns by state regulators regarding their ability to have sufficient information on market operations to conduct oversight activities. The board recommended revisiting RTO policies regarding the issue of state regulator access to information.

The South Joint Board expressed support for "appropriate, cost-effective, improvements in the transparency with which the regional transmission system is planned and operated and the manner in which transmission congestion is managed."[24] However, the Joint Board felt that many of these issues were already being addressed in proposed Commission reforms of the Open Access Transmission Tariff (OATT) and did not see a need for the board to comment further on the issue.

The West Joint Board viewed transparency in terms of access to pricing information and also in terms of transparency that could be added by an independent entity. With respect to access to pricing information, the board noted the "numerous, robust trading hubs"[25] in the Western Interconnection and did not see a need for further

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[21] Northeast Report, p. 13.

[22] PJM-MISO Report, p. 21 and p. 30.

[23] PJM-MISO Report, p.33.

[24] South Report, p. 11.

[25] West Report, p. 11.

recommendations in this area. With regard to the increased transparency that could be added by an independent entity, the board did not believe this transparency was sufficient to justify the creation of such an entity.[26]

Independence

The issue of independence (a principal subject of the DOE Report) focuses on the relationship of the dispatching entities to the owners of the resources being dispatched. More specifically, the issue was raised in joint board discussions in terms of how transmission-owning utilities dispatch resources they do not own, and whether dispatch by an independent third party (possibly, but not necessarily, an ISO or an RTO) was a better alternative to utility dispatch.

In the regions where RTOs operate the dispatch, the RTO is regarded as sufficiently independent from market participants, and neither the Northeast nor PJM-MISO Joint Boards recommends any changes to the basic RTO independence structure. The PJM-MISO board does emphasize the importance of independence and addresses a recommendation on independence to the RTOs, emphasizing the need to continue to strive for independence, and the role of state and federal regulators in overseeing RTO independence.[27]

With respect to the development of independent entities outside the existing RTOs in the region, the South Joint Board concludes that voluntary formation of such entities should be encouraged where they are cost effective, subject to a test of their benefits to customers, and with appropriate state regulatory approvals.[28]

Concerned that "independent dispatch entities not be created for their own sake," and believing there still needs to be a better demonstration of potential benefits from independent entities, the West Joint Board does not recommend further analysis at this time.[29]

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[26] West Report, p. 17.

[27] PJM-MISO Report Summary, recommendation 12.

[28] South Report, p. 13.

[29] West Report, p. 15.

Inclusion of Demand Response and Other Factors in Dispatch

Most regions discuss demand response in terms of RTO or state-level initiatives that vary considerably across regions. Improving demand response is generally regarded as a potentially important way of reducing costs and increasing overall reliability, but the boards do not propose specific recommendations for incorporation of these programs into the dispatch, beyond programs currently implemented by RTOs or conducted under state direction.

After review of the progress of demand response in the NYISO and in ISO-NE, the Northeast Joint Board concludes that the RTOs were making significant progress on including demand response initiatives at the wholesale level. Accordingly, the Northeast Joint Board does not recommend any additional demand response requirements for the RTOs.[30]

The PJM-MISO Joint Board expresses more concerns about progress on demand response than the Northeast Joint Board did. Concerned about the lack of price-responsive demand and its impact on prices, the board recommends that PJM and MISO "must develop more ways for demand response to participate in the dispatch."[31] The board recommendation also emphasizes that improvement in demand response is not a responsibility of RTOs alone and encourages the RTOs to work closely with appropriate state regulators and policymakers.[32]

In the West, the issue of including demand response in the dispatch arose in the context of discussion of the demand response initiatives of California and the CAISO. The West Joint Board addressed demand response initiatives, and related programs such as renewable portfolio standards that can affect the operation of the dispatch, in terms of the definition of SCED. In this context, the West Joint Board recommended broadening the definition of SCED to include public policies that affect the dispatch in addition to purely economic or security considerations.[33]

The issue of including demand response in the dispatch was not raised in the South Joint Board report.

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[30] Northeast Report, p. 16.

[31] PJM-MISO Report, p. 46.

[32] PJM-MISO Report, p. 46 and Summary, recommendation 16.

[33] West Report, p. 22.

Other Topics Addressed in Joint Board Recommendations

There were several topics that received attention in the board discussions, but were not as prominent in joint board recommendations as the issues discussed above. These included the topic of efficient dispatch as an alternative to economic dispatch, the use of a pay-as-bid approach as an alternative to the uniform clearing price in the RTO dispatch, and the benefits of SCED, particularly as implemented in RTOs. Joint board discussions and recommendations on these topics are summarized in this section.

The topic of "efficient dispatch" appears to have arisen during discussions leading up to EPAct 2005 concerning measures that could result in a more efficient use of scarce natural gas resources[34] and potentially exert downward pressure on natural gas prices.[35] Efficient dispatch is typically taken to mean dispatching the units with the lowest heat rate first, i.e., those that use the least amount of natural gas to generate a megawatt of electric energy. Economic dispatch meets electricity demand at the lowest cost. DOE noted that economic dispatch would generally result in running higher efficiency natural gas units before lower efficiency units but that efficient dispatch would presumably modify economic dispatch to ensure that the more physically efficient gas-fired units are always dispatched before less efficient units. DOE expressed skepticism about implementing a new procedure that would add costs to the dispatch without clearly commensurate benefits.[36]

The South Joint Board endorses the use of economic dispatch, but felt that commenting on the broader issue of efficient dispatch was beyond the scope of their task.[37] The PJM-MISO Joint Board believes an economic dispatch, properly performed, would include the issues of concern in efficient dispatch, and the issue was "resolved, at least for the time being, in favor of economic dispatch."[38]

The use of pay-as-bid as an alternative to uniform price for setting prices in the dispatch was addressed by both the Northeast and PJM-MISO Joint Boards. In the uniform price approach, currently used by the RTOs, electricity is bought and sold at a single price at each location. Under the pay-as-bid alternative, each generator would be paid the price of their bid to supply power to the RTO at the generator's location. Although the was considerable discussion of the potential benefits of switching to a pay-

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[34] DOE Report, p. 11.

[35] Transcript of First West Joint Board Meeting, Palm Springs CA, November 13, 2006, p. 136.

[36] DOE Report, p.6-7.

[37] South Report, p. 9.

[38] PJM-MISO Report, p. 35.

as-bid approach, both RTOs noted that many other factors favor the uniform price approach, and neither recommends changes to their current pricing approach.[39]

On the topic of benefits from SCED, the Northeast Joint Board observes that SCED is not a new procedure, and maintains it is important to distinguish the implementation of SCED and the implementation of markets based on the SCED, since SCED does not require a market-based approach. The Northeast Joint Board examined data collected by the New York Power Pool (NYPP) when it was formed in 1977, that indicated $281 million in savings for the year 1981 ($600 million in 2006 dollars.) The boards did not attempt to assess the broader benefits of the market-based SCED as implemented in their regions. The PJM-MISO Joint Board made the only specific recommendation regarding benefits, emphasizing the ongoing importance of demonstrating benefits from SCED and recommending that the RTOs establish a clear benchmark to assess the degree to which the reliability and least cost objectives of SCED are being captured. The board also encouraged the RTOs to assess the benefits of standardized reliability rules.[40]

Recommendations from the DOE Report to Congress

The DOE Report to Congress contained three recommendations that are relevant to the issues addressed by the joint boards, and each joint board addressed some or all of these three issues in their reports.

First DOE Recommendation: review dispatch practices

The DOE Report recommended that the joint boards consider conducting in-depth reviews of selected dispatch entities, including some Investor Owned Utilities (IOUs), to determine how they conduct Economic Dispatch.[41] None of the boards believed this effort was feasible within the time and resources available to them, and they did not

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[39] Further details on this issue can be found in Appendices containing the Northeast and PJM-MISO Reports, and in the following studies filed in Docket No. AD05-13: Natalia Fabra, David Harbord et al , "Designing Electricity Auctions: Uniform, Discriminatory and Vickrey", filed May 3, 2006; Giulio Federico and David Rahman titled "Bidding in an Electricity Pay-as-Bid Auction"; filed May 3, 2006; Par Holmberg, "Comparing Supply Function Equilibria of Pay-As-Bid and Uniform-Price Auctions"; filed May 3, 2006; and "California Power Exchange's Blue Ribbon Panel Report re the study on the Pricing in the California Power Exchange Electricity Market: Should California Switch from Uniform Pricing to Pay-as-Bid Pricing", filed December 1, 2005.

[40] PJM-MISO Report, p. 35-36.

[41] DOE Report, p. 52.

propose specific recommendations for future work.

In the Northeast and PJM-MISO regions, the joint boards do not recommend any additional steps beyond the current reviews that RTOs perform to review their dispatch practices.

The South Joint Board sees potential merit in a study of dispatch practices, and concludes that such a study conducted "in a dispassionate, fact-based manner might resolve some of the issues that were raised by various participants in the Joint Board process." [42] Although the South Joint Board states it would tend to be supportive of such a study, the board did not make a recommendation, believing there would need to be further clarification of the nature and scope of the study, the data needed and available, the funding source, and the resources to be used before any recommendation to pursue the study could be made.

The West Joint Board recommends not pursuing such a study. The West Joint Board believes that the dispatch needs to remain flexible and that going into the details of how particular utility dispatches are conducted would delve too deeply into local deviations from pure economic dispatch, without adding much value.[43]

Second DOE Recommendation: standardize dispatch contract terms

The DOE Report recommended that the Commission and DOE explore Electric Power Supply Association (EPSA) and Edison Electric Institute (EEI) proposals for more standard contract terms for placing and accepting supply offers, operating requirements, and non-performance penalties and encourage stakeholders to undertake these efforts.[44] The Northeast and PJM-MISO Joint Boards did not comment on this recommendation. The South Board agrees that exploration of these issues could be helpful, but has a number of concerns including that any such exploration "be undertaken with the understanding that adequate flexibility in wholesale contracting should be preserved in the interests of assuring the most economical service for customers,"[45] and makes no recommendation to pursue the proposals. The West Joint Board finds this recommendation to be a reasonable one to pursue, as long as the development of such a contract is pursued on a regional rather than a national basis.[46]

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[42] South Report, p. 14.

[43] West Report, p. 23.

[44] DOE Report, p. 51.

[45] South Report, p. 14.

[46] West Report, p. 24.

Third DOE Recommendation review dispatch tools

The DOE report recommended that economic dispatch technology tools be scrutinized. These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.[47]

The Northeast Joint Board notes that RTOs and ISOs have the most advanced dispatch tools, and recommends that the Commission request the ISO-RTO Council (IRC) "take the lead in identifying 'best practices' to guide future improvements to these tools."[48] The other joint boards did not recommend any action.

[47] DOE Report, p. 53.

[48] Northeast Report, p. 20.

Appendix A: Joint Board Members

The members of the Northeast Joint Board are:

- Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Paul G. Afonso, Massachusetts Department of Telecommunications and Energy, Vice Chair of the Joint Board
- Chairman William M. Flynn, New York State Public Service Commission, Vice Chair of the Joint Board
- Commissioner Jack R. Goldberg, Connecticut Department of Public Utility Control
- Chairman Kurt Adams, Maine Public Utilities Commission
- Chairman Thomas B. Getz, New Hampshire Public Utilities Commission
- Chairman Elia Germani, Rhode Island Public Utilities Commission
- Chairman James Volz, Vermont Public Service Board

The members of the PJM/MISO Joint Board are:

- Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Kevin K. Wright, Illinois Commerce Commission, Vice Chair of the Joint Board
- Chairman Kenneth D. Schisler, Maryland Public Service Commission, Vice Chair of the Joint Board
- Commissioner Dallas Winslow, Delaware Public Service Commission
- Chair Agnes A. Yates, District of Columbia Public Service Commission
- Chairman David Lott Hardy, Indiana Utility Regulatory Commission
- Chairman John Norris, Iowa Utilities Board
- Chairman Mark David Goss, Kentucky Public Service Commission
- Commissioner Laura Chappelle, Michigan Public Service Commission
- Commissioner Kenneth Nickolai, Minnesota Public Utilities Commission
- Chairman Jeff Davis, Missouri Public Service Commission
- Chairman Greg Jergeson, Montana Public Service Commission
- Mr. Paul Malone, Regulatory, Planning & Contracts Manager, Nebraska Public Power District
- Commissioner Frederick F. Butler, New Jersey Board of Public Utilities
- Commissioner Sam J. Ervin IV, North Carolina Utilities Commission
- Commissioner Susan E. Wefald, North Dakota Public Service Commission
- Chairman Alan R. Schriber, Public Utilities Commission of Ohio

- Chairman Wendell F. Holland, Pennsylvania Public Utility Commission
- Chairman Gary W. Hanson, South Dakota Public Utilities Commission
- Director Pat Miller, Tennessee Regulatory Authority
- Mr. Howard Spinner, Director, Division of Economics and Finance, Virginia State Corporation Commission
- Mr. Earl Melton, Director, Engineering Division, Public Service Commission of West Virginia
- Chairperson Daniel R. Ebert, Public Service Commission of Wisconsin
- Assistant Deputy Minister Garry Hastings, Department of Energy, Science & Technology, Manitoba (observer)

The members of the South Joint Board are:

- Chairman Joseph T. Kelliher, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Sam J. Ervin, IV, North Carolina Utilities Commission, Vice Chair of the Joint Board
- President Jim Sullivan, Alabama Public Service Commission
- Chairman Sandra L. Hochstetter, Arkansas Public Service Commission
- Commissioner J. Terry Deason, Florida Public Service Commission
- Ms. Pandora Epps, Internal Consultant, Georgia Public Service Commission
- Chair Brian J. Moline, Kansas Corporation Commission
- Commissioner James M. Field, Louisiana Public Service Commission
- Dr. Christopher Garbacz, Director, Economics and Planning Division, Mississippi Public Utilities Staff, representing the Mississippi Public Service Commission
- Commissioner Steve Gaw, Missouri Public Service Commission
- Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
- Chairman Jeff Cloud, Oklahoma Corporation Commission
- Vice Chairman G. O'Neal Hamilton, South Carolina Public Service Commission
- Mr. Pat Miller, Director, Tennessee Regulatory Authority
- Commissioner Julie Caruthers Parsley, Public Utility Commission of Texas

The members of the West Joint Board are:

- Commissioner Suedeen Kelly, Federal Energy Regulatory Commission, Chair of the Joint Board
- Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the Joint Board
- Commissioner Marc L. Spitzer, Arizona Corporation Commission
- Commissioner Dian M. Grueneich, California Public Utilities Commission

- Chairman Gregory Sopkin, Colorado Public Utilities Commission
- Commissioner Thomas J. Schneider, Montana Public Service Commission
- Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
- Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
- Chairman Lee Beyer, Oregon Public Utility Commission
- Commissioner Dustin Johnson, South Dakota Public Utilities Commission
- Commissioner Barry Smitherman, Public Utility Commission of Texas
- Chairman Ric Campbell, Utah Public Service Commission
- Chairman Mark Sidran, Washington Utilities and Transportation Commission
- Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

Appendix B: Agenda for First Joint Board Meetings

Agenda for First Northeast Joint Board Meeting

AGENDA FOR THE NORTHEAST JOINT BOARD MEETING

FERC Commissioner Nora Mead Brownell, Chair
Massachusetts DTE Chairman Paul Afonso, Vice Chair
New York PSC Chairman Bill Flynn, Vice Chair
November 29, 2005

- Opening Remarks by chair and vice chairs

- Presentation: FERC staff
  - Economic dispatch: concepts, practices, and issues

- Presentation: U.S. Department of Energy
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act [pending issuance of the report]

- Panel: Regional Transmission Organizations

  - To address:
    - What are the benefits and costs of SCED, compared to the previous system used for dispatch, or to other potential alternatives? What specific benefits has SCED offered? Can you quantify these benefits, and, if so, please do so.
    - What lessons did you learn in implementing SCED? In particular, were there unanticipated benefits or costs that should be kept in mind when considering changes or improvements to the current SCED?
    - How does the operation of SCED relate to the operation of the regional market? How would a market operate in your region without SCED?
    - What effect has SCED had on the reliability of the electric system in your region? Can you quantify the effect, and, if so, please do so.
    - What effect has SCED had on the cost of electric energy in your region, after adjusting for input costs such as fuel? Can you quantify the effect, and, if so, please do so.
    - How can an RTO's/ISO's SCED resources be more optimally dispatched?

  - Panelists:
    - Mark Lynch, President and CEO, New York Independent System Operator
    - Gordon van Welie, President and CEO, ISO New England

  - Question and answer session

- Lunch

- Panel: Stakeholders

  - To address:
    - Current application of economic dispatch in region (what quantitative and qualitative benefits have been realized, what lessons have been learned, what noteworthy improvements have been made)
    - Possible improvements to current economic dispatch practices (what weaknesses currently exist that should be a high priority for improving, what improvements have been requested that the RTOs/ISOs have not addressed, if you could start from scratch, how should economic dispatch be facilitated in your region)
    - How does economic dispatch affect the markets – spot, day-ahead, bilaterals?
    - Further consolidation of economic dispatch by integrating the two New York and New England dispatch systems into one system?

  - Panelists:
    - Daniel W. Allegretti, Vice President - Regulatory and Legislative Affairs, Constellation
    - Richard Bolbrock, Vice President – Power Markets, Long Island Power Authority
    - Kevin Burke, President and Chief Executive Officer, ConEdison
    - Michael Calviou, Vice President - Transmission Commercial and Regulatory, National Grid
    - Steve Corneli, Vice President – Regulatory and Governmental Affairs, NRG Energy
    - Doug Horan, Senior Vice President - Strategy, Law and Policy, NStar
    - Edward N. Krapels, Director, ESAI Gas and Power Services (on behalf of Neptune LLC)
    - Robert M. Loughney, Couch, White, Brenner, Howard & Feigenbaum
    - Tom Rudesbusch, Duncan, Weinberg, Genzer and Pembroke PC (on behalf of the New York Association of Public Power)
    - Donald Sipe, Preti Flaherty Beliveau Pachios & Haley LLC (representing the Industrial Energy Consumer Group)

  - Question and answer session

- Break

- Board members' discussion
    - Issues and objectives to be addressed in joint board report

- Closing remarks -- chair and vice chairs

Agenda for First PJM-MISO Joint Board Meeting

AGENDA FOR THE PJM/MISO JOINT BOARD MEETING

FERC Commissioner Nora Mead Brownell, Chair
Maryland PSC Chairman Ken Schisler, Vice Chair
Illinois Commerce Commission Chairman Kevin Wright, Vice Chair
November 21, 2005

- Opening Remarks by chair and vice chairs

- Presentation: FERC staff
  - Economic dispatch: concepts, practices, and issues

- Presentation: U.S. Department of Energy
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act [pending issuance of the report]

- Panel: Regional Transmission Organizations

  - To address:
    - What are the benefits and costs of SCED, compared to the previous system used for dispatch, or to other potential alternatives? What specific benefits has SCED offered? Can you quantify these benefits, and, if so, please do so.
    - What lessons did you learn in implementing SCED? In particular, were there unanticipated benefits or costs that should be kept in mind when considering changes or improvements to the current SCED?
    - How does the operation of SCED relate to the operation of the regional market? How would a market operate in your region without SCED?
    - What effect has SCED had on the reliability of the electric system in your region? Can you quantify the effect, and, if so, please do so.
    - What effect has SCED had on the cost of electric energy in your region, after adjusting for input costs such as fuel? Can you quantify the effect, and, if so, please do so. How can RTOs be more optimally dispatched?

  - Panelists:
    - Jim Torgerson, President and Chief Executive Officer, Midwest ISO
    - Phil Harris, President and Chief Executive Office, PJM Interconnection

  - Question and answer session

- Lunch

- Panel: Stakeholders

    - To address:
        - Current application of economic dispatch in region (what quantitative and qualitative benefits have been realized, what lessons have been learned, what noteworthy improvements have been made)
        - Possible improvements to current economic dispatch practices (what weaknesses currently exist that should be a high priority for improving, what improvements have been requested that the RTOs have not addressed, if you could start from scratch, how should economic dispatch be facilitated in your region)
        - How does economic dispatch affect the markets – spot, day-ahead, bilaterals?
        - What effect do non-participants have on economic dispatch?

    - Panelists:
        - Doug Collins, Direct System Planning, Alliant Energy
        - Fred Kunkel, Manager Transmission Service, Wabash Valley Power
        - Ed Tatum, Assistant Vice President – Rates and Regulation, Old Dominion Electric Cooperative
        - Steven Naumann, Vice President - Wholesale Market Development, Exelon Corp.
        - John Orr, Constellation
        - Joseph Welch, President and Chief Executive Officer, International Transmission Company
        - Brett A. Kruse, Manager – Market Integration Service, Calpine
        - TBA, industrial customer

    - Question and answer session

- Break

- Board members' discussion
    - Issues and objectives to be addressed in joint board report

- Closing remarks -- chair and vice chairs

Agenda for First South Joint Board Meeting

AGENDA FOR THE SOUTH JOINT BOARD MEETING
November 13, 2005

Note: questions from, and discussion among, board members appropriate after all presentations.

- Opening remarks (1:00-1:05 p.m.)
  - FERC Chairman Joseph Kelliher, Chair of South Joint Board

- Remarks (1:05-1:10 p.m.)
  - Mississippi PSC Commissioner Michael Callahan, Vice Chair of South Joint Board

- Presentation by FERC staff (1:10-1:40 p.m.)
  - Economic dispatch: concepts, practices and issues

- Presentation: U.S. Department of Energy (1:40-2:10 p.m.)
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act

- Stakeholder panel (2:10-3:40 p.m.)

  - Current application of economic dispatch in region
    - Who performs the dispatch?
    - How is the dispatch determined?
    - What is the geographic scope of the dispatch?
    - Are there resources not included in the dispatch? Would including them improve the dispatch?
    - Are there resources that present challenges in incorporating them into the dispatch (e.g., hydro resources)?
    - How do transmission congestion and the dispatch affect each other? How would improvements in one affect the other?
    - How are individual dispatches in the region coordinated?
    - How is the dispatch communicated to affected generation operators?
    - Are there technical/infrastructure impediments that interfere with implementing the economic dispatch?

  - Possible improvements to current economic dispatch practices
    - What are the potential benefits and costs of those improvements?
    - Are there institutional, regulatory, or statutory impediments to the identified improvements?

- Additional topic for ERCOT:
  - What are the benefits and costs of the way ERCOT dispatches now compared to the way dispatch was done prior to the ERCOT-wide dispatch?

- Additional topic for SPP:
  - Describe the way SPP's imbalance proposal would change the dispatch in SPP.
  - What are the benefits and costs of SPP's imbalance proposal compared to the way dispatch is performed now?

Panelists:
- Scott Henry, Vice President of Energy Policy, Duke Power
- John Hurstell, Vice President of Energy Management, Entergy Corporation
- Robert Priest, General Manager, Clarksdale Public Utilities
- David Beam, Senior Vice President of Power Supply, North Carolina Electric Membership Cooperative
- Sam Henry, President and Chief Executive Officer, SUEZ Energy Marketing North America
- Robert O'Connell, Manager, Regulatory Affairs, Williams Power
- Carl Monroe, Senior Vice President, Operations and Chief Operating Officer, Southwest Power Pool
- Kent Saathoff, Director of System Operations, ERCOT
- Industrial customer, TBD

- Break (3:40-3:55 p.m.)

- Board members' discussion (3:55-4:50 p.m.)
  - Issues and objectives to be addressed in joint board report (see Attachment B of this notice).

  ["Open microphones" for audience participation]

- Closing remarks by Chairman Kelliher and Commissioner Callahan (4:50-5:00 p.m.)

Agenda for First West Joint Board Meeting

AGENDA FOR THE WEST JOINT BOARD MEETING
November 13, 2005

Note: questions from, and discussion among, board members appropriate after all presentations.

- Opening remarks (1:00-1:05 p.m.)
  - FERC Commissioner Suedeen Kelly, Chair of West Joint Board

- Remarks (1:05-1:10 p.m.)
  - Idaho PUC Commissioner Marsha Smith, Vice Chair of West Joint Board

- Presentation by FERC staff (1:10-1:40 p.m.)
  - Economic dispatch: concepts, practices and issues

- Presentation: U.S. Department of Energy (1:40-2:10 p.m.)
  - Regarding report on economic dispatch required by section 1234 of the Energy Policy Act

- Stakeholder panel (2:10-3:40 p.m.)

  - Current application of economic dispatch in region
    - Who performs the dispatch?
    - How is the dispatch determined?
    - What is the geographic scope of the dispatch?
    - Are there resources not included in the dispatch? Would including them improve the dispatch?
    - Are there resources that present challenges in incorporating them into the dispatch (e.g., hydro resources)?
    - How do transmission congestion and the dispatch affect each other? How would improvements in one affect the other?
    - How are individual dispatches in the region coordinated?
    - How is the dispatch communicated to affected generation operators?
    - Are there technical/infrastructure impediments that interfere with implementing the economic dispatch?

  - Possible improvements to current economic dispatch practices
    - What are the potential benefits and costs of those improvements?
    - Are there institutional, regulatory, or statutory impediments to the identified improvements?

  - Additional topic for California ISO:

- What are the benefits and costs of the way CAISO dispatches now compared to the way dispatch was done prior to CAISO?

Panelists:

- Mark Rothleder, Principal, Market Developer, California ISO
- Doug Larson, Vice President – Regulation, PacifiCorp
- John Coggins, Manager – Supply and Trading, Salt River Project
- Kieran Connolly, Manager-Regional Coordination, Bonneville Power Administration
- Marcie Edwards, General Manager, Anaheim Public Utilities
- Richard Kurtz, Vice President of Power Services, Arizona Electric Power Cooperative
- Robert Kahn, Executive Director, Northwest Independent Power Producers Coalition
- Greg Patterson, Director, Arizona Competitive Power Alliance
- Industrial customer, TBD

- Break (3:40-3:55 p.m.)

- Board members' discussion (3:55-4:50 p.m.)
  - Issues and objectives to be addressed in joint board report (see Attachment B of this notice).

  ["Open microphones" for audience participation]

- Closing remarks by Commissioner Kelly and Commissioner Smith (4:50-5:00 p.m.)

Appendix C: Northeast Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	Docket No. AD05-13-000

Study and Recommendations Regarding Security Constrained Economic Dispatch (SCED) in the Northeast

by

The Joint Board on Economic Dispatch for the Northeast Region

May 24, 2006

I. Overview

The Northeast Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298 Economic Dispatch. The members of the Northeast Joint Board are:

> Commissioner Nora Mead Brownell, Federal Energy Regulatory Commission, Chair of the Joint Board
> Commissioner Paul G. Afonso, Massachusetts Department of Telecommunications and Energy, Vice Chair of the Joint Board
> Chairman William M. Flynn, New York State Public Service Commission, Vice Chair of the Joint Board
> Commissioner Jack R. Goldberg, Connecticut Department of Public Utility Control
> Chairman Kurt Adams, Maine Public Utilities Commission
> Chairman Thomas B. Getz, New Hampshire Public Utilities Commission
> Chairman Elia Germani, Rhode Island Public Utilities Commission
> Chairman James Volz, Vermont Public Service Board

The Northeast Joint Board met in public session on November 29, 2005 in Boston Massachusetts and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes '*security constrained economic dispatch*'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

In the following sections, this report provides a description of the basic concept of Security Constrained Economic Dispatch (SCED); describes background on the variations in dispatch procedures in the Northeast, and gives a summary of the issues raised and considered by the board, together with any recommendations made to address these issues. The principal sources for these sections are presentations to the board and written comments submitted, discussions among the Joint Board members, the DOE report under EPAct 2005, Section 1234 and the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: The Basics in the Northeast Region

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[1] This definition describes the basic way all utilities or ISOs/RTOs dispatch resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand, demand varies greatly over the course of a day, week, and seasons, the costs of generation from different types of units vary greatly, and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

SCED occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, SCED decides which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast and transmission constraints. SCED uses either cost-based or bid-based offers to select the most economic generator mix, considering transmission constraints. In selecting the most economic generators to commit, SCED also takes into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, minimum time a generator must run once it is started, and environmental restrictions.

In addition, forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive

[1] September 30, 2005 order at P14. These operations are normally automated and carried out by computer software; however, the operations are monitored by transmission engineers who can override the software when necessary.

generators may have to replace cheaper units.[2] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, SCED decides in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and SCED must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software.

The economic dispatch problem is generally considered to be a mathematically simpler problem to solve, although recent advances (e.g. the use of mixed-integer-programming (MIP) for unit commitment) have advanced the available technology to the point where many earlier limitations on problem size have been eliminated. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available resources are considered. In non-organized markets this may not always be possible due to various reasons including limitations in open access transmission tariffs based on Order 888.

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[2] If the more expensive units are not allowed to set the market prices, these units are referred to as "out of merit" and their above market costs must be recovered through uplift.

III. Economic Dispatch in the Northeast

Security Constrained Economic Dispatch (SCED) in the northeast is performed primarily by two entities – ISO New England (ISONE), which has been designated as a Regional Transmission Organization (RTO) and the New York ISO (NYISO). Both entities operate day-ahead and real-time energy markets that constitute the commitment and dispatch components of SCED described in the last section. There is a long history of SCED is the Northeast under these entities and prior to this under the NY Power Pool and NEPOOL.

There is much in common between the two regions in how they perform SCED. Both NYISO and ISO-NE have consolidated control areas and perform the dispatch function centrally. SCED has been performed in both regions since the 1970s under the predecessor power pools and continues with enhancements under the markets that have been in operation since 1999. They both incorporate transmission constraints and unit operational constraints within the dispatch and commitment software. They both include all available resources without regard to ownership. Both regions have significant load pockets, e.g., New York City, Long Island, Boston and Southwest Connecticut that require higher cost local generation. Both regions have had limitations on reflecting the full spectrum of physical constraints in their software that has resulted in uplifts, i.e., costs that are not included in the market price and are administratively allocated to participants. Currently, this appears to be a bigger problem in New England.

A. NYISO and NYPP

The NYPP was formed in response to the Northeastern blackout of 1965. By 1977 it had implemented a form of SCED that dispatched all of the utility-owned generation in New York State based not on market-driven bidding, but on regulated generator costs. The NYPP SCED did not incorporate non-utility generation. Nevertheless, it produced substantial savings by dispatching generation on a least-cost basis and by taking advantage of supply and load diversity across the pool. The resulting savings were split among the NYPP's utility members and went to the ultimate benefit of ratepayers.

The NYPP SCED made it possible for energy transactions to be scheduled and priced more efficiently than was possible before 1977. Prior to the SCED, the NYPP could only facilitate bilateral transactions among its member utilities by acting as an intermediary. This was done through telephone calls and allowed transactions to be scheduled on, at best, an hourly basis. Under SCED, transaction scheduling and pricing was fully automated and took place every five minutes. In addition, the adoption of SCED allowed the NYPP to develop an "Interchange Evaluation" program, which evaluated energy transactions between neighboring control areas in the United States and Canada, including New England, the mid-Atlantic, Ontario and Quebec. This evaluation improved inter-control area energy deliveries in the Northeast and made out-of-state

economic resources more readily available to the NYCA.

The adoption of SCED also permitted a more efficient allocation of Operating Reserves among NYPP members to satisfy total pool requirements. The NYPP estimated that SCED, and the various external transaction scheduling improvements that it made possible, was responsible for $281 million in savings in 1981, which would translate to approximately $600 million in 2005 dollars.

In the 1990s, the NYPP's members formed the NYISO. From its inception in 1999, the NYISO used a bid-based SCED that was open to all electricity resources in the NYCA, and to out-of-state suppliers selling into New York, that chose to participate in it. The NYISO SCED is a key part of the NYISO's market that uses a locational-based marginal pricing system ("LBMP") very similar to the locational marginal pricing (LMP) regimes that have evolved in the ISO New England, PJM Interconnection, and Midwest Independent System Operator regions.

The NYISO implemented major enhancements to its real-time dispatch and market software on February 1, 2005. It now has fully co-optimized day-ahead and real-time markets for energy, three different reserves products, and regulation that produce the lowest possible total cost for these products consistent with reliability constraints. The NYISO's new software platform includes a real-time unit commitment ("RTC") function that complements the NYISO's day-ahead security constrained unit commitment process using the superior information that becomes available closer to the actual real-time dispatch. RTC is capable of looking two and a half hours ahead and can commit "quick start" resources such as hydro units and certain gas turbines in fifteen minute increments in order to facilitate a more efficient co-optimized, least-cost SCED for energy ancillary services. The RTC is integrated with and uses the same software as the NYISO's real-time dispatching system, which helps them to work together to produce the best possible dispatch and price signals. There are nearly three hundred active market participants in the NYISO markets today. In 2005, the NYISO settled electricity transactions totaling approximately $10.7 billion and has cleared over $40 billion of wholesale transactions since its inception in 1999.

B. ISO-NE and NEPOOL

The New England Power Pool (NEPOOL) was formed in 1971 by the region's private and municipal utilities to foster cooperation and coordination among utilities in the six-state region. During the next three decades, NEPOOL created a regional power grid that now includes more than 350 separate generating plants and more than 8,000 miles of transmission lines.

ISO New England was created in 1997 in a region where 88 percent of the region's generation is unregulated, the most in the nation. Working closely with the NEPOOL, now a group of generators, utilities, marketers, public power companies and end users, ISO New England implemented wholesale markets in 1999. Today, more than 260 Market Participants complete in excess of $10 billion of wholesale electricity transactions annually, about a quarter of the power sold in the region (the remainder is sold through negotiated, long-term contracts).

ISO New England has enhanced these markets, notably in 2003, by adding features such as a Day-Ahead Market. In the five years following the opening of wholesale markets in 1999, New England's capacity has increased by 40 percent. Wholesale electricity prices in New England, adjusted for fuel costs, have declined by 5.7 percent since the first full year of market operations. Prices dropped by 11 percent during the four-year period from 2001-2004.

Security Constrained Economic Dispatch (SCED) is an essential component of the ISO-NE markets. It figures in the day-ahead unit commitment performed under the day-ahead market and in the real-time balancing market.

New England's Economic Dispatch is coordinated with the Economic Dispatch of neighboring control areas through hourly exports and imports of power. These exports and imports are generally scheduled by market participants responding to electricity prices in each control area, with participants seeking to buy power in the lower priced control area and sell in the higher priced control area. If the volume of transactions increases until either the prices at the source and delivery points are equal, or until the transfer limits are reached, than the dispatch is efficiently coordinated between the control areas. Because this efficient coordination does not regularly occur between New York and New England, the two control areas are investigating ways to improve the coordination. Possible solutions include the two ISO's explicitly coordinating interface flows and reducing the lead time required for participants to schedule flows across the interface between the regions.

IV. Observations and Issues

This section describes the issues considered by the Joint Board and identifies any recommendations in the record. Based on the discussion at the initial meeting, there appeared to be an overall consensus that economic dispatch and markets have created benefits for customers in the Northeast. There is a long history of economic dispatch in the region that was mentioned by many participants along with an emphasis on least cost

security constrained dispatch without regard to ownership[3]. There was some disagreement on the precise measure of these benefits.

A. Observations

- *Benefits from economic dispatch*

The NYISO estimated the benefits of SCED at roughly 100 million dollars per year from 1977 to 1999 yielding a cumulative benefit of 2 billion dollars[4]. A savings of 281 million dollars or roughly 24 percent of the total market transactions was cited in 1981. Precise estimates for the period since 1977 were not cited. However, the NYISO has made several enhancements to SCED since then and estimates that the benefits have likely increased even further. The NYISO cited estimated a five percent decline based on average monthly costs on a fuel adjusted basis from 2000 – 2004[5].

ISO-NE cited an estimated total savings due to the regional economic dispatch from 1970 – 1977 at over $1.4 billion in 2004 dollars[6]. The ISO-NE cited a 5.6 percent reduction in the average wholesale cost of electricity from 2000-2004 which translates to a 700 million dollars per year after netting out fuel costs[7]. The ISO-NE also noted a 5 - 6 percent improvement in generator availability and significant new investment as a result of the advent of markets.

Despite the extensive references to the benefits of economic dispatch and markets in general, there were also concerns raised on related market issues (e.g., the impact of high gas prices on uniform price markets) as well as a discussion of further improvements than can be made, e.g. improved inter-regional coordination, better modeling of constraints in software etc. In the remainder of this section, we summarize some of the major issues that were brought up.

- *Benefits of economic dispatch and benefits of markets*

There was considerable discussion at the meeting on the benefits that have been realized through markets. Some participants suggested that since economic dispatch is a required enabler of markets, it makes sense to look at the benefits created by the market as a whole when evaluating the benefits of economic dispatch[8]. Others disagreed observing that

[3] Mr. Bolbrek at p 111 of transcript.
[4] Mark Lynch at p 49 of transcript.
[5] Mark Lynch at p 59 of transcript.
[6] Gordon van Welie at p 66 of transcript.
[7] Gordon van Welie at p 68 of transcript.
[8] Gordon van Welie at p 67 of transcript.

economic dispatch does not necessarily require markets[9].

Some participants observed that improvements in generation availability may not be entirely attributable to the introduction of LMP based day-ahead markets but rather a result of how capacity credits are calculated[10]. Measuring the benefits of economic dispatch precisely can be complex[11].

- *Concerns about efficient vs. economic dispatch*

Some participants raised questions about whether economic dispatch can ensure efficient dispatch[12]. The difference between economic and efficient dispatch has been discussed in the recent DOE report related to section 1234 of EPACT. The reasons the two can be different are two-fold (1) if the entire set of available resources is not considered as an input to the economic dispatch algorithm, the result will not be efficient[13], and (2) if offer prices do not reflect costs, the dispatch may not be efficient from a heat-rate perspective[14].

B. Specific Market and Dispatch Issues

- *Wider geographical scope of economic dispatch*

Some improvements such as the elimination of pancaking in rates have already been made[15]. Other improvements that are under way include better inter-regional transaction scheduling and pricing of external nodes[16]. Overall, there appears to be consensus that better coordination of dispatch across interfaces within the region (e.g. New York and New England) as well as interfaces with external areas (e.g., PJM and Canada) is desirable. However, some participants also raised caution on what might be a reasonable expectation of benefits.

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[9] Mr. Rudebusch at p 162 of transcript.
[10] Mr. Bolbrock at p85 of transcript.

[11] Mr. Burke at p 99 of transcript.

[12] Keating, Meyer and Meroney at pp 26-30 of transcript.

[13] Meroney at p 28 of transcript.

[14] Keating at p 30 of transcript.

[15] Mark Lynch at p. 60 of transcript.
[16] Gordon van Welie at p 78 of transcript.

There is disagreement on specific approaches to improve coordination of economic dispatch between New York and New England. Some participants favored improvements realized through improved transaction scheduling by market participants on a shorter time frame than is available currently, while others favored a stronger integration using a "Virtual Regional Dispatch" (VRD) model[17]. Both the New York ISO and ISO New England have looked at the VRD approach for some time with little actual progress on implementation. More recently, they have started looking at taking smaller steps by improving the granularity of scheduling across their boundaries under the Interregional Transaction Scheduling or ITS project. By allowing schedules to be submitted closer to real-time and more frequently, the expectation is that market participants would be able to capture at least some of the benefits that can come from a fully integrated economic dispatch. Some participants raised concerns about implementation complexity and costs[18].

- *Concerns about uniform price markets*

In response to the recent high gas prices and their impact on electricity prices, there have been concerns expressed about uniform clearing price markets and whether there could be additional savings under other market models[19]. A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited[20]. However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix[21]. Some participants noted that economic dispatch does not necessarily require a single clearing price methodology and took issue with prices set by gas fired plants being paid to coal and nuclear plant[22]. Other participants noted that the alternative design of pay-as-bid auctions could potentially result in lower overall prices but this would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity[23].

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[17] See comments submitted by National Grid, Dan Allegretti at p 106 and Michael Calviou at p 118 of transcript.

[18] Mr. Loughney at p 160 of transcript.

[19] Commissioner Brownell at p 97 of transcript.

[20] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

[21] Bob Loughney at p 158 of transcript.

[22] Mr. Rudebusch at p 162 of transcript.

[23] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

- *Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch*

Some participants raised concerns about dispatch actions taken outside the security constrained economic dispatch software[24]. Such actions are necessary when either the operational constraints of generators or transmission constraints cannot be fully represented within the software. Generating sources dispatched in this manner do not affect the calculation of market prices and are paid separately via an uplift payment. If uplifts are improperly allocated to market participants they can have additional adverse affects on markets. One example cited at the conference was the impact of uplifts allocations in New England and their impact on virtual trading. The allocation has recently been modified to address the problem[25]. One participant noted that the biggest issue is the challenge in reflecting all security constraints in security constrained unit commitment and security constrained economic dispatch[26].

There have been recent improvements to dispatch models used in the Northeast. For example, NYISO introduced in February 2005, enhancements to its real time dispatch software that allows co-optimization of energy and reserves in addition to a shortened evaluation period for real-time unit commitment[27].

Uplifts can often result from limitations of software in modeling physical constraints, e.g. combined cycle plants in unit commitment in the Boston area. The economic impact of such uplifts can in some instances be greater than efficiency gains on seams issues. The ISO-New England has therefore made addressing this issue a high priority[28].

Other improvements such as the use of Mixed Integer Programming (MIP) software for better combined cycle generator modeling are being considered but are in the research and development phase[29].

- *Incorporation of demand response into economic dispatch*

There are opportunities for better integration of demand response in economic dispatch that can further improve infrastructure utilization[30]. This is an area where state regulators

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[24] Pete Fuller at p. 43, Dan Allegretti at p 105 and Steve Corneli at p 139 of transcript.
[25] Steve Corneli at p 140 of transcript.
[26] Steve Corneli at p 138 of transcript.
[27] Mark Lynch at pp 59-60 of transcript.
[28] Gordon van Welie at p 78 of transcript.
[29] Gordon van Welie at p74 of transcript.
[30] Gordon van Welie at p 72 and p 83 of transcript and Burke at p 93 of transcript.

and the RTOs can work together. Participants noted that while organized markets have generally similar demand response programs, there are also differences. For example, ISO New England considers demand response to be a critical resource that can be drawn upon in the absence of quick start peaking resources and has made efforts to incorporate demand response into its commitment and dispatch software[31].

- *Further Improvements in market transparency*

Many participants noted the significance of transparent price signals in making markets work better and encouraging investment. Some participants expressed a desire to allow releasing market bid data sooner than the six-month lag with which is released currently[32]. They cited other markets such as the UK and Australia where this is done on a daily basis and argued that US markets have now matured enough to allow this data to be released sooner. The ISO-NE responded saying they would be open to such a suggestion and the right venue to discuss it would be the stakeholder committee process[33].

- *Better utilization of the interconnections with External Areas*

Additional benefits of economic dispatch may be possible by looking by looking at external interfaces with regions outside New York and New England. A specific example was the 2000 MW limit on the Phase 2 HVDC U.S. Interconnector between New England and Quebec that is currently being used at 1200 MW due to constraints further down the system in New York and PJM[34]. A decrease in flows from Quebec to New York may be able to yield as much as three times higher flows into New England. Thus, further benefits for the region may be possible by improved coordination between New York, New England and Quebec.

- *Capacity markets and new investments*

One participant noted that existing markets have not performed well in promoting new investment through price signals. Instead, new investment is largely driven by contracts arranged via RFPs. A missing element of markets in the region relates to the refinement

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[31] Gordon van Welie at p 90 of transcript.
[32] Michael Calviou at p 122 and Doug Horan at p 148 of transcript.
[33] Gordon van Welie at p 129 of transcript.
[34] See Michael Calviou at p 120 of transcript.

of existing mechanisms for capacity markets[35].

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, The Value of Economic Dispatch, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

- FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct ED. [36] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices should from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow NUGs and other resources to compete effectively and serve load.

- FERC and DOE should explore EPSA and EEI proposals for more standard contact terms and encourage stakeholders to undertake these efforts.[37] Specifically, the EEI proposed that NUGs should commit to provide energy at specified price for specified time to meet unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

- Current economic dispatch technology tools deserve scrutiny.[38] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

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[35] Steve Corneli at p 142 of transcript.

[36] The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005, United States Department of Energy, November 7, 2005, page 52.

[37] Ibid, p 51.

[38] Ibid, p 53.

V. Board Recommendations

A. Further Improvements in Market Transparency

While not directly related to the implementation of SCED, improved market transparency is important for monitoring and establishing confidence in the pricing and dispatch determined by SCED. A proposal was made to allow market bid data to be released with a less than six-month lag. The six-month lag was introduced to protect market participants from having to reveal current operations and competitive bidding strategies, and to discourage collusion. However, a shorter lag period would provide quicker public access to bid data, which would strengthen public monitoring of market behavior and help ensure confidence in the competitiveness of the markets; it would also enhance the ability of market participants to quickly identify inefficiencies. One party suggested that a month's delay would be sufficient to protect market participants.[39] Another party observed that other electricity markets in the U.K. and Australia release bid data on the day or the day after the market outcome.[40] ISO-NE and NYISO stated that they were open to suggestions on making market bid data available with a shorter lag time and that this should be pursued through the appropriate ISO committee processes.[41] No party objected to this proposal.

APPA submitted comments questioning whether bids reflected actual marginal costs, or whether bids might be inflated due to market power.[42] This question cannot be answered solely by providing better access to bid data; it also requires information about "actual" marginal costs, which involve confidential supplier information. For this reason, APPA requested an analysis by the Northeast Joint Board comparing generator bids to their actual marginal costs, as supplied to ISO-NE and NYISO.

Recommendation: 1) ISO-NE and NYISO should pursue, with market participant input, making market bid data available to the market with a shorter lag time. 2) **NYISO and ISO-NE have market monitoring responsibilities with FERC oversight. For example, NYISO's Market Power Mitigation Measures (OATT Attachment H) defines procedures for calculating "reference levels" for bids based on estimates of actual marginal costs, and establishes mitigation measures (including reducing bids to reference levels) when the bids appear to represent an abuse of market power (i.e. would raise prices significantly above competitive levels). Any concerns associated with market power should be addressed as part of ISO market monitoring efforts, not in this proceeding.**

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[39] NSTAR Electric – Doug Horan, p. 149 of transcript.

[40] National Grid - Michael Calviou, p. 122 of transcript.

[41] Gordon van Welie at p. 129 of transcript; Mark Lynch at p. 13 of 2/13 transcript.

[42] American Public Power Association, "Re: Joint Boards on Security Constrained Economic Dispatch, Docket No. AD05-13-000 (Northeast Region)", letter of 2/17/2006.

B. Wider geographical scope of economic dispatch

Participants generally agreed that just as there are significant benefits associated with utilizing SCED in any given region, there are additional benefits to be derived by expanding the scope of economic dispatch over a wider geographic area, but there are also significant impediments and drawbacks to implementing a single SCED regime for, for example, the New York and New England regions combined. However, much of the benefit of a larger scope can be obtained by improvements that would allow electricity to flow between regions in a more economically efficient manner. The impediments to those more efficient flows are commonly referred to as "seams" issues, and these issues can relate to differing regional market rules, operating or scheduling protocols, and many other causes. Much progress has already been made in this area, with the elimination of through-and-out rates and improved transaction checkout procedures between New York and New England. The main focus of the participants in the Northeast to address this problem centered on two general proposals commonly referred to as Intra-hour Transaction Scheduling (ITS) and Virtual Regional Dispatch (VRD)[43]. The ITS proposal focuses on improving the processes to allow market participants to more effectively be able to schedule power flows between regions in response to changing prices and system conditions, and in particular to be able to do so in a shorter timeframe than is now possible. The VRD proposal would allow ISOs and RTOs themselves to change interchange power flows between each other if appropriate when the interchange schedule set by market participants' transaction schedules result in an inefficient dispatch.

Recommendation: Thus far neither proposal has been developed in sufficient detail to be implemented. We recommend that both NYISO and ISO-NE work together and with the market participants towards the development of mechanisms to address the specific seams issues discussed here. As an initial step, both NYISO and ISO-NE should meet within 90 days to coordinate their initiatives and file a plan with FERC describing the time line to address the seams discussed in this section.

C. Improvements in modeling of unit operational constraints and transmission constraints in economic dispatch

Market participants[44] correctly pointed out that not all unit and system constraints are modeled in the security constrained economic dispatch software used by ISO-NE and

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[43] It should be noted a major seam, transmission rate pancaking between the two control areas, has already been eliminated.

[44] Pete Fuller (p. 43), Dan Allegretti (p. 105), Steve Corneli (p. 139) in 11/29/05 Northeast Joint Board for Economic Dispatch transcript.

NYISO. The resulting impacts vary from the need for human intervention in the dispatch to the addition of uplift charges which distort market prices[45]. Component models for multiple combined-cycle unit configurations are being refined and their use would allow for more accurate modeling of large units[46] and result in an improved economic dispatch. Where these improved models have not yet been incorporated into the dispatch, they should be scheduled for inclusion in the next software upgrade.

The increased modeling of system constraints (e.g. include voltage and stability constraints) would result in more precise dispatches and result in better market signals[47]. Technology, however, stills need to advance before implementation can be initiated. The principle tool for incorporating additional system constraints is the security constrained optimal power flow (OPF) program. The basic difference between today's security constrained unit dispatch software and a security constrained OPF is the use of an AC power flow instead of a DC power flow-based program. The switch to AC-based software would increase the run time for a single scenario from minutes to well over an hour with today's technology. Therefore, the use of a security constrained OPF even in the day-ahead markets is impractical at this time. The ISOs should monitor the technology for increased processing speed with the goal of switching to a security constrained OPF for economic dispatch when it is feasible.

Recommendation: The NYISO and ISO-NE should incorporate additional unit and system constraints in economic dispatch software as modeling and technology improve.

D. Incorporation of demand response into economic dispatch

Some participants called for better integration of demand response into economic dispatch and for state regulators and RTOs to work together on this. The NYISO already allows demand response programs – the Special Case Resource and Day Ahead Demand Response program - to participate and compete with generation. In addition, FERC has recently directed the NYISO to allow demand response participants to offer demand side response in the ancillary services market[48]. Continued improvements should be coordinated through the NYISO working groups, to ensure that the proposals will be practical and will work as intended.

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[45] Commissioner Nora Brownell (p. 16) in 2/13/06 Northeast Joint board for Economic Dispatch transcript.

[46] Gordon van Welie (p. 74) in 11/29/05 transcript.

[47] Ibid.

[48] ER04-230-010, ER04-230-014 and ER04-230-019; Letter from FERC to NYISO dated January 26, 2006.

ISO-NE currently administers five demand response programs including three real-time programs that support system reliability and two programs that provide incentives for demand to respond to high real-time or day-ahead wholesale market prices. ISO-NE's goal is to transform these currently out-of-market programs into ones that are directly integrated into the region's wholesale and retail electricity markets. To this end, ISO-NE's Ancillary Services Markets (Phase II) project will integrate "asset-related demands" into real-time operations, which would allow demand resources to more efficiently balance load and generation and offer reserve services in real time. Additionally, ISO-NE will also be implementing a Demand Response Reserves Pilot Project to determine the ability of small demand resources (e.g., less than 5 MW) to meet operational requirements for reserve resources and to investigate more cost-effective communication and telemetry solutions that would allow small resources to participate in the wholesale electricity markets. Finally, ISO-NE will be engaged in a project to integrate demand resources into the Forward Capacity Market, should the Commission approve the recently-filed settlement agreement in FERC Docket Nos. ER03-563-000, -030, and -055.

Further, NYPSC is actively promoting dynamic electric pricing for large customers that would facilitate Demand Response. For example, the NYPSC recently implemented mandatory hourly pricing as the default rate for large customers[49]. This could place over 5,000 MW of load on the hourly pricing default tariff in the coming months. Currently, none of the New England States require default service to be priced on a dynamic basis. Accordingly, ISO-NE has approached the New England Conference of Public Utility Commissioners (NECPUC) to analyze, design, and implement dynamic pricing solutions that would capture greater price-responsive demand in the New England region. To date, ISO-NE has sponsored studies quantifying the benefits of dynamic pricing and recently submitted testimony in a Connecticut regulatory proceeding recommending that a dynamic rate be applied to default service for customers with maximum demands greater than or equal to 350 kW. The proposed rate included a three-part, time-of-use, variable peak pricing design applicable to the commodity portion of service where the Peak Period Rate would be based on the average of the corresponding hourly Day-Ahead Energy Market prices during the peak period (defined as 1:00 p.m. to 7:00 p.m. weekdays) for the applicable day and Load Zone.

Recommendation: We believe that incorporation of Demand Response in the wholesale market is making progress in both NYISO and ISO-NE. In addition, regulators in New York are promoting dynamic pricing for retail electric customers. Efforts are underway in New England to include these resources in developing markets. We expect these efforts to continue, and as a result to provide greater opportunities for market participation by these resources. With these ongoing

[49] Case 03-E-0641, Proceeding on motion of the Commission regarding expedited implementation of mandatory hourly pricing for commodity service.

initiatives, we do not recommend any additional requirements as part of this proceeding.

E. Better utilization of the interconnections with External Areas:

Increased use of interconnection capability provides opportunities for additional economic interchange of energy. However, it has long been recognized in regional planning that power transfers between control areas can impact system operations in other control areas. To date, most analysis has revolved around the principle of "do no harm" such that if inter-tie transfers produced negative operational impacts in the other control areas, the transfer levels are limited to below those impact thresholds. Economic studies have generally not taken place to determine if it would be beneficial to increase the inter-tie transfers and make arrangements with the other control area to take mitigating measures. An example offered is the Quebec-New England inter-tie where transfer levels are limited by constraints in New York and PJM. There are some indicators that a 100 MW reduction in transfers between Quebec and New York, coupled with leaving the 100 MW system capacity in New York unloaded, would increase the transfer capability from Quebec to New England by 300 MW.[50]

<u>Recommendation:</u> **The ISOs should investigate better utilization of their interconnections with other areas which could provide additional economic transaction opportunities. The ISOs should perform a technical evaluation of its inter-ties, including the Quebec-New England inter-tie, to determine a) what operating adjustments in other control areas could be made to accommodate increased use of the inter-ties; and, b) what system upgrades would be required to fix the constraint.[51] The ISOs should then perform a market-impact analysis of the expanded use of the inter-ties. As a threshold, the analysis should determine if there would be a net region-wide benefit from the proposed increased use of the inter-ties and how they would be spread across control areas. If there is not a net benefit, inter-tie maximization should be deferred. If there is a net regional benefit, operating adjustments and cost impact mitigation strategies should be identified and protocols developed to make these opportunities available to the market. The possibility of system upgrades should be included in regional planning processes for evaluation in those forums.**

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[50] Michael Calviou (p. 120) in 11/29/05 transcript.

[51] Commissioner Nora Brownell (p.20) in 2/13/06 transcript.

F. Refining capacity markets

Some participants called for refinements to capacity markets in order to promote new investment. Commissioner Brownell noted that there were many efforts underway across the northeast regarding capacity markets, but due to ex-parte rules, it would not be appropriate to address those efforts here.[52]

Recommendation: No further action is recommended in the context of this proceeding given the current proceedings underway. However, FERC should continue to evaluate potential seams issues with neighboring regions as new market designs are adopted.

G. Re-examining uniform price auctions

All suppliers in the spot market are paid the uniform spot market price determined by SCED, adjusted for line losses and congestion. Of course, most supply is sold prior to the spot market at contractual prices, so that only a small portion of supply is actually paid the spot price determined by SCED. However, the spot market price does provide a benchmark for comparison to contractual prices. Moreover, all suppliers must participate in SCED to coordinate overall supply and demand.

Some participants called for re-examining the use of uniform price auctions that allow gas fired generators to set the price for coal and nuclear plant.[53] Gordon van Welie (ISO-NE) explained that under the current uniform price auction, baseload units such as coal and nuclear plants may act as "price takers," bidding their marginal cost, which may be zero, in order to guarantee they are dispatched. They are paid the uniform clearing price, which is generally above their marginal cost; the difference goes towards recovering their capital investment and other fixed costs. The debate has been over the "pay-as-bid" approach, in which suppliers whose bids were accepted (and thus were dispatched) would be paid their individual bids rather than a uniform clearing price. However, under the pay-as-bid approach, baseload units would have to change their bidding strategy: In order to recover the same capital investment and other fixed costs, they would have to increase their bids to a level reflecting their estimates of the market clearing price. So there would not be much difference in the prices paid, but the pay-as-bid method would be less robust than the current uniform price auction in terms of producing efficient dispatch. Other participants elaborated that, under pay-as-bid, baseload units might submit bids slightly below their estimate of the market clearing price, in order to guarantee dispatch; this could potentially result in baseload units being

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[52] Commissioner Brownell at p. 23 of transcript of 2/13/2006.

[53] Tom Rudebusch at p 162 of transcript.

paid a little bit less on some occasions, but it would destroy incentives for cost reflective bids, which in turn would lead to inefficient dispatch and may not be worth the complexity. Moreover, adopting pay-as-bid in order to try to reduce payments to baseload units would discourage future investments in baseload generation. [54] A report written during the California power crisis that explained the benefits of uniform price auctions and why it ultimately results in lower prices for customers was cited.[55] However, some participants expressed a desire to revisit the issue using actual bidding data and a more realistic assumption of generation mix.[56]

Some participants argued that, under the uniform price auctions, the only way loads can capture the benefits of lower cost coal and hydro resources is via long-term bilateral contracts or investments in new baseload projects.[57] Mr. Van Welie observed that the high prices facing consumers in the Northeast are due to their over-dependence on natural gas-fired generation. The solution is not to change the market design, but to change the siting rules to permit greater investment in new baseload generation that does not depend on natural gas.[58] Mark Lynch added that the Northeast's existing market design is producing all the right price signals; but to ensure new entry, the siting issues must now be resolved.[59]

Recommendation: The current uniform clearing price approach has been in place for several years. Comments in this proceeding do not justify a departure from the established uniform clearing price model. We do not make any recommendation about this approach at this time.

H. Review dispatch practices

The DOE report (p.52) noted a lack of easily comparable information regarding dispatch models and implementation by different entities and areas, and recommended that the FERC-State Joint Boards consider conducting in-depth reviews of selected dispatch entities, including some investor-owned utilities, to determine how they conduct economic dispatch. These reviews would document all deviations from pure least-cost, merit-order dispatch and distinguish entity-specific or regional practices from regulatory,

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[54] Harry Singh at p 187 and Don Sipe at p 198 of transcript.

[55] Gordon van Wylie at p 97 and p 182 of transcript. The report "Pricing of the California Electricity Market - Should California Switch from Uniform Pricing to Pay-As-Bid Pricing" is available as a part of the record.

[56] Bob Loughney at p 158 of transcript.

[57] Tom Rudebusch at p. 163 of transcript.

[58] Gordon van Wylie at p. 172 of transcript.

[59] Mark Lynch at p. 175 of transcript.

environmental and reliability-driven constraints, with an eye toward identifying potential discrimination against certain resources. While discrimination against NUG resources is not an issue in the Northeast in that ISO-NE and the NYISO commit and dispatch resources without regard to ownership, the NYISO is currently, in conjunction with its review of rules applicable to wind and solar power, commencing a global review of its rules to ensure that all types of resources are treated equitably.

Recommendation: We do not recommend any additional steps be undertaken in this proceeding beyond what NYISO and ISO-NE are contemplating doing as part of their regular improvements to their operations.

I. Standardize Contract Terms

The DOE report (p.51) recommends that DOE and FERC should explore the EPSA and EEI proposals for more standard contract terms and conditions for NUG-to-buyer contracting and should encourage stakeholders to undertake these efforts, which should benefit the entire wholesale electric industry and its customers. These proposals relate to the conditions for inclusion of NUG resources in a utility's economic dispatch queue and their provision of ancillary services such as voltage support and regulation, along with associated performance standards, compensation and penalties. ISO-NE and the NYISO both dispatch generation resources without regard to ownership and compensate and penalize units according to established FERC-approved tariff rules.

Recommendation: This recommendation does not appear to be relevant to the Northeast Board, and for regions without organized markets might better be addressed in an industry forum such as the NAESB.

J. Review Dispatch Tools

The DOE report (p.53) noted the diversity of size and scope of the various dispatch areas and recommended scrutiny of the technical quality of current economic dispatch technology tools including software, data, algorithms, and assumptions, with an eye toward enhancements to these tools and elimination of any inherent resource biases.

Recommendation: Given that the most advanced tools and models to date have been developed and administered by the nation's ISOs and RTOs, it is recommended that FERC request of the ISO-RTO Council (IRC) to take the lead in identifying "best practices" to guide future improvements to these tools.

Appendix D: PJM-MISO Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	Docket No. AD05-13-000

Report on Security Constrained Economic Dispatch

By

The Joint Board for the PJM/MISO Region

Submitted to the Federal Energy Regulatory Commission on:

May 24, 2006

Summary of the PJM/MISO Region Joint Board Recommendations

This section summarizes the recommendations that are discussed in greater detail in Section V of the report. Not all Joint Board members agree on all aspects of this report or on all aspects of these recommendations. In particular, some Joint Board members believe that some aspects of these recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. In addition, the Joint Board report does not address retail service, which is strictly a matter for states to decide.

1. An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

2. Appropriate efforts should be made to acquire necessary data to assess the impact of the SCED conducted by PJM and MISO on market participant forward bilateral contracting.

3. While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue such standardization if its benefits exceed the costs for customers.

4. The RTOs' common market development effort should include proposals for improving SCED over the seam between PJM and MISO. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly and in a cost-effective manner.

5. With the Joint Operating Agreement, PJM and MISO developed a method for addressing transmission constraints in one RTO through redispatch by the other RTO when doing so is cost effective. MISO has suggested a way to improve this limited coordinated dispatch by exchanging preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. The RTOs are encouraged to further explore this idea of additional SCED coordination, taking cost-effectiveness into account.

6. The RTOs are encouraged to continue timely analyses of the cost and technical feasibility issues involved with expanding the geographic scope of SCED. The continued analyses should encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO should analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO managed SCED, as requested by utilities that seek voluntary membership in the RTO. However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.

7. Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

8. The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan, are, nevertheless, not getting implemented in a timely manner.

9. Provided that the RTO uses proper measures and a proper approach for inclusion of an economic transmission project (intended to address congestion issues) in its transmission expansion plan, the obligation on a transmission owner to exercise best efforts to implement such a project should be no different than its obligation to use best efforts to implement a baseline reliability project.

10. The RTOs are encouraged to continually improve their analytical modeling and forecasting capability to better assess beneficiaries of transmission expansion so as to improve transmission cost allocation.

11. The RTOs are encouraged to devote adequate resources and substantial management attention to joint transmission planning and expansion processes, so as to pull our respective geographic areas together, improve the operation of RTO-managed SCED, and facilitate a robust competitive electricity market.

12. RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

13. Some state regulators believe that they do not currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

14. When determining their respective dispatches, MISO uses marginal losses and PJM uses average losses. The material presented to the Joint Board shows that, while there may be implementation issues to resolve, using marginal losses improves dispatch efficiency. Accordingly, the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

15. The operation of SCED must take transmission ancillary services into account. PJM and MISO have distinctly different methods of treating ancillary services. There are potentially significant efficiencies to be gained through improved co-optimization of ancillary services and energy in the dispatch and PJM and MISO are encouraged to continue to strive to improve on efficiencies gained in the area of ancillary services.

16. The PJM and MISO markets must develop more ways for demand response to participate in the dispatch. Improvement in demand response opportunities is not just an RTO responsibility.

The Joint Board encourages PJM and MISO to work with state regulators and policy-makers to improve SCED by improving cost effective demand responsiveness to price.

17. The Joint Board is not proposing any recommendations on the SCED framework issues of SCED definition, SCED history, or the debate over efficient versus economic dispatch at this time.

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I. BACKGROUND AND OVERVIEW

A. Convening of Joint Boards Pursuant to EPAct 2005

Section 1298 of the Energy Policy Act of 2005 ("EPAct") adds a new Section 223 to the Federal Power Act ("FPA") requiring the Federal Energy Commission ("FERC" or "Commission") to convene regional Joint Boards pursuant to FPA Section 209 to study the issue of security constrained economic dispatch ("SCED") for the various market regions.[1] FPA Section 209, in turn, authorizes the Commission to refer matters to joint boards that include state representatives.[2] Section 1298(c) guides the work of the SCED Joint Boards by stating:

> The sole authority of each joint board convened under this section shall be to consider issues relevant to what constitutes "security constrained economic dispatch" and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned and to make recommendations to the Commission regarding such issues.[3]

On September 30, 2005, the FERC issued an "Order Convening Joint Boards pursuant to Section 223 of the Federal Power Act."[4] The Joint Board for the PJM Interconnection, LLC and Midwest Independent Transmission System Operator, Inc. ("PJM/MISO") region is one of four joint boards convened by the Commission in the September 30 Order.[5] The states included on the PJM/MISO Region Joint Board are: Delaware, District of Columbia, Illinois, Indiana, Iowa, Kentucky, Maryland, Michigan, Minnesota, Missouri, Montana, Nebraska, New Jersey, North Carolina, North Dakota, Ohio, Pennsylvania, South Dakota, Tennessee, Virginia, West Virginia and Wisconsin.[6]

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[1] Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

[2] Section 209 of the FPA, 16 U.S.C. § 824h states in part,

The Commission may refer any matter arising in the administration of this Part to a board to be composed of a member or members, as determined by the Commission, from the State or each of the States affected or to be affected by such matter. Any such board shall be vested with the same power and be subject to the same duties and liabilities as in the case of a member of the Commission when designated by the Commission to hold any hearings.

[3] Pub. L. No. 109-58, 1298(c), 119 Stat. 594, ___ (2005).

[4] Joint Boards on Security Constrained Economic Dispatch, 112 FERC ¶ 61,353 (Sept. 30, 2005) (Joint Board Order).

[5] References in this report to "the Joint Board" are to the Joint Board for the PJM/MISO Region unless specified otherwise.

[6] The members of the PJM/MISO Joint Board are Chair: Commissioner Nora Mead Brownell (Federal Energy Regulatory Commission); Vice Chair: Commissioner Kevin K. Wright (Illinois Commerce Commission); Vice Chair: Chairman Kenneth D. Schisler (Maryland Public Service Commission). Members: Commissioner Dallas Winslow (Delaware Public Service Commission); Chair Agnes A. Yates (District of Columbia Public Service Commission); Chairman David Lott Hardy (Indiana Utility Regulatory Commission); Chairman John Norris (Iowa Utilities Board); Chairman Mark David Goss (Kentucky Public Service Commission); Commissioner Laura Chappelle (Michigan Public Service Commission); Commissioner Kenneth Nickolai (Minnesota Public Utilities Commission); Chairman Jeff Davis (Missouri Public Service Commission); Chairman Greg Jergeson (Montana

The Commission's September 30 Order noted the directives in EPAct Section 1298 and summarized them as follows:

> Each joint board is authorized to: (1) "consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) " make recommendations to the Commission regarding such issues."[7]

Section 1298(d) of EPAct requires the Commission to submit a report to Congress by August, 2006, regarding the recommendations of the joint boards.

B. Summary of the DOE Report on the Value of Economic Dispatch

Section 1298 is not the only section of EPAct that addresses SCED. For example, Section 1234 of EPAct requires the U.S. Department of Energy ("DOE") to coordinate and consult with the States and to annually conduct a study and distribute a report on SCED issues.[8] While the PJM/MISO Region Joint Board's work effort was separate from that performed by the DOE under Section 1234, our report has been informed by the DOE's work.[9]

EPAct Section 1234 directs the United States Department of Energy ("DOE") to:

(1) study the procedures currently used by electric utilities to perform economic dispatch;
(2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and
(3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

Public Service Commission) Mr. Paul Malone, Regulatory, Planning & Contracts Manager (Nebraska Public Power District); Commissioner Frederick F. Butler (New Jersey Board of Public Utilities); Commissioner Sam J. Ervin IV (North Carolina Utilities Commission); Commissioner Susan E. Wefald (North Dakota Public Service Commission); Chairman Alan R. Schriber (Public Utilities Commission of Ohio); Chairman Wendell F. Holland (Pennsylvania Public Utility Commission); Chairman Gary W. Hanson (South Dakota Public Utilities Commission); Director Pat Miller (Tennessee Regulatory Authority); Mr. Howard Spinner, Director, Division of Economics and Finance (Virginia State Corporation Commission); Mr. Earl Melton, Director, Engineering Division (Public Service Commission of West Virginia); Chairperson Daniel R. Ebert (Public Service Commission of Wisconsin). Assistant Deputy Minister Garry Hastings, Department of Energy, Science & Technology, Manitoba served as an "observer."

[7] Joint Board Order, at P14.

[8] Section 1234 of the Energy Policy Act, Pub. L. No. 109-58, § 1234, 119 Stat. 594, ___ (2005)

[9] The Commission's September 30 Order directs the joint boards to "take into account the DOE report as they proceed with their own efforts." See Joint Board Order at P15.

On November 7, 2005, DOE submitted its first annual report to Congress pursuant to Section 1234 of EPAct. The DOE's report is titled "*The Value of Economic Dispatch.*"

DOE's 2005 report was prepared using a survey of stakeholders and a literature search on economic dispatch issues. The EPAct states that the DOE's report may make recommendations to Congress and the states on legislative or regulatory changes related to economic dispatch.[10]

While the DOE Report has "the use of non-utility generation within economic dispatch" as one of its specific major focuses, it also examines economic dispatch more broadly. The DOE Report concludes that "there is room to improve economic dispatch practices to reduce total cost of electricity and increase grid reliability."[11] The DOE advises that "the FERC-State Joint Boards on Economic Dispatch (created pursuant to Sec. 1298 of EPAct) may wish to study these, starting with a more detailed examination of economic dispatch practices and administration than was possible" in the DOE's limited initial study.[12]

The DOE Report contains three recommendations that are directly or tangentially relevant to the SCED issues that the Joint Board considered. These three recommendations are described below.

- The FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some investor owned utilities, to determine how they conduct economic dispatch. These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices from regulatory, environmental and reliability-driven constraints. These reviews could assist the FERC and the states in rethinking existing rules or crafting new rules and procedures to allow non-utility generators and other resources to compete effectively and serve load.[13]

- The FERC and the DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts. Specifically, the EEI proposed that non-utility generators should commit to provide energy at a specified price for a specified time to meet a unit commitment schedule and there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.[14]

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[10] Pub. L. No. 109-58, § 1234(c), 119 Stat. 594, ___ (2005).

[11] United States Department of Energy, The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005, November 7, 2005 at 6 (DOE Report).

[12] DOE Report, at 6.

[13] DOE Report at 52.

[14] DOE Report at 51.

- Given the diversity of size and scope of the dispatch areas now operating across the nation and the need for economic dispatch to continue to produce affordable, reliable outcomes, the technical quality of current economic dispatch technology tools—software, data, algorithms and assumptions—deserve scrutiny. Any enhancements to these tools, including identification and elimination of any resource biases in the calculation methods, will improve the reliability and affordability of the nation's electricity supplies.[15]

Although it is not explicitly stated, the DOE's recommendations appear to apply more directly to SCED in regions of the country where SCED is not centrally conducted by an independent RTO or ISO. However, the DOE recommendations are at least partially relevant for other regions and we have kept them in mind during our deliberations.

C. Joint Board Sessions

The Joint Board met in public session on November 21, 2005, in Chicago and on February 12, 2006, in Washington, D.C. under the leadership of Commissioner Nora Brownell as Chair and Chairman Kenneth Schisler and Commissioner Kevin Wright as co-Vice Chairs.[16] At the Chicago session, the Joint Board heard from a number of speakers including speakers from DOE, FERC, MISO, PJM, and several industry stakeholder representatives. The Joint Board also issued data requests to PJM and MISO in October, 2005 and on March 8, 2006. Finally, several interested parties filed Comments and other materials on Joint Board matters in Dkt. No. AD05-13-000 and those Comments are available on the Commission's web-site.

The Joint Board met informally via conference call on May 1, 2006, and subsequently conducted a vote of the members via e-mail on the report and recommendations.

In the following sections, this report provides: a general overview of the concept of SCED (Section II); a description of SCED as practiced in PJM and MISO (Section III); a review of issues raised and considered in the Joint Board process (Section IV); and a list of Joint Board recommendations (Section V). The principal sources for the material in these sections are: presentations to the Joint Board; written comments submitted by interested parties; discussions among the Joint Board members; the report submitted to Congress by DOE pursuant to Section 1234 of EPAct; and responses by PJM and MISO to Joint Board data requests.

Not all Joint Board members agree on all aspects of this report or on all aspects of the recommendations in Section V below. In particular, some Joint Board members believe that some aspects of the recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. Accordingly, nothing in this report should be

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[15] DOE Report at 53.

[16] Transcripts from those sessions are available on the Commission's web-site at http://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=2362&CalType=%20&Date=2%2f12%2f2006&CalendarID=116.

interpreted as being binding on individual Joint Board members or their respective agencies or preventing such members or agencies from taking positions that deviate from those adopted in this report should circumstances warrant. In addition, the Joint Board report does not address retail service, which is strictly a matter for states to decide.

II. GENERAL OPERATION OF SECURITY CONSTRAINED ECONOMIC DISPATCH

A. The Definition and Concept of SCED

The basics of SCED are described in this section to establish a common understanding of the issue before addressing details and recommendations. Section 1234(b) of EPAct defines "economic dispatch" as: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." FERC proposed to adopt this definition of economic dispatch as the definition of SCED for purposes of the Joint Board's work.[17] This definition was discussed at the first PJM/MISO Region Joint Board meeting and was generally used to guide the Joint Board's discussion.[18]

The definition of SCED is such that it takes, as a premise, that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served. In some ways, the Joint Board's objective is to examine the extent to which MISO's and PJM's operation of SCED satisfies the expectations implied by the definition of SCED.

There are a number of unique challenges to supplying electricity. In particular, production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and by season; the costs of generation from different types of units vary greatly; and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load economically and reliably. SCED is designed to be an optimization process that takes account of these factors in selecting the generating units to dispatch so that a reliable supply of electricity at the lowest cost possible under the conditions prevailing in each dispatch time interval can be delivered.

B. The Process of Economic Dispatch

The economic dispatch process generally occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time). In the unit commitment stage, operators must decide which generating units should be committed to be on-line for each hour, for the next 24-hour period (hence the term "day ahead"), based on the load forecast and knowledge about the availability and expected performance of system facilities. In selecting the most economic generators to commit, system operators must

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[17] Joint Board Order at P14.

[18] PJM/MISO Joint Board November 21, 2005 Meeting on Security Constrained Economic Dispatch, Docket No. AD05-13-000 at 20 (Nov. 21, 2005 Tr.).

take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. System operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance. System operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as environmental limits on annual unit output and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

Forecasted conditions that can affect the transmission grid must also be taken into account to ensure that the units committed can reasonably be expected to meet load reliably. This is the "security" aspect of the unit commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the economically optimal unit commitment cannot be carried out reliably, relatively more expensive generators may have to be committed in place of cheaper units.[19] This step also requires evaluation of possible contingencies. System operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day's dispatch.

In the unit dispatch stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment process and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz, per North American Electric Reliability Council ("NERC") standards. This is generally done through regulation reserves by using (or directing Balancing Authorities to use) Automatic Generation Control ("AGC") to follow system load and conditions as needed. In addition, transmission flows must be monitored to ensure that flows stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve changing the dispatch, curtailing schedules, or shedding load. System operators must frequently check conditions and issue adjusted unit dispatch instructions accordingly.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software generally has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail, while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints, and, in some cases even the network model, might vary in economic dispatch software.

Recent advances in computing technology (e.g. the use of mixed-integer-programming for unit commitment) have generally made the economic dispatch problem mathematically simpler to

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[19] This is known as "out of merit" unit commitment.

solve (all other things equal) than was historically the case. Available technology has advanced to the point where many earlier limitations on solvable problem size have been overcome. Advances in hardware and software now make it technologically feasible to undertake security constrained economic dispatch over very large regions.

In addition to differences in models used in economic dispatch software, a major factor that can impact the benefits of economic dispatch is whether or not all available economic resources are considered. In non-organized markets (i.e., outside of RTOs/ISOs) there are concerns expressed by some providing information to the Joint Board that this may not always occur due to various reasons, including limitations in open access transmission tariffs based on Order 888.[20] However, witnesses in the PJM/MISO Region Joint Board process did not generally raise significant issues about non-utility generators' level of access to the RTOs' unit dispatch process.[21]

III. EXAMINATION OF SCED IN PJM AND MISO

A. History of SCED

In their November 21 written Comments, both PJM and MISO explain that SCED is not new. As MISO explained, "SCED has always been the necessary tool for ensuring reliable operations in modern systems."[22] Similarly, AEP explained that, "Prior to the development of large RTOs, most, if not all, control areas throughout the United States utilized some form of security constrained economic dispatch to minimize the generation cost of supplying the load."[23]

PJM's Comments explain that the history of security constrained dispatch in PJM goes back to PJM's formation in 1927.[24] As PJM and MISO explain, the tools and methods of SCED have evolved and the scope of SCED, especially in the RTO regions, has expanded in recent times. However, the RTOs are not aware of any method other than SCED, in some form, for operating an electrical system to pursue the dual goals of least-cost and reliable operation.

B. PJM and MISO SCED Operations and Practices

There are four basic ways that SCED, as operated by PJM and MISO, differs from the general description of SCED as previously described: (1) PJM and MISO generally dispatch over a broader region; (2) PJM and MISO generally use demand bids and supply offers, rather than generating unit costs, as the economic measure for dispatch; (3) PJM and MISO generally use locational marginal pricing ("LMP"), rather than Transmission Line Loading Relief ("TLR"), as

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[20] See, e.g., DOE Report at 45-47 and MISO Comments at 4-5.

[21] For example, DOE's Mr. Meyer stated that, in conducting the DOE survey, they "did notice that the non-utility generators in the organized markets seemed generally pretty content with the way economic dispatch was going." Nov. 21 Tr., at 28.

[22] MISO Comments at 9.

[23] AEP Comments at 5.

[24] PJM Comments at 1.

the method for managing transmission congestion; and (4) PJM and MISO have entered into a Joint Operating Agreement ("JOA") by which they coordinate elements of their dispatch and, in some circumstances, undertake redispatch in one RTO for congestion that appears in the geographic area of the other RTO. Each of these four differences will be discussed below.

PJM and MISO each consider the resources owned/operated by their respective market participants and then each RTO evaluates their respective market sellers' offers as a single resource pool. The broader regional resources available to the RTOs (as contrasted with individual utility dispatch) results in a dispatch stack containing generators from all generating-owning members of the RTOs and some generation resources outside the RTOs. Uncoordinated and separate dispatches by different individual utility companies in response to constraints (under most circumstances) would not be the same as an area-wide dispatch coordinated by either RTO, given the scope of the RTOs. It is also noteworthy that the sum of stand-alone dispatches by individual utility companies is not the same as a regional least cost dispatch when there are transmission constraints that affect and in turn are affected by the dispatch of multiple utility companies throughout the region. That there are economic and operational benefits from pooling generation resources is almost axiomatic. Other factors held constant, separate dispatches would inevitably result in higher total production costs to serve load.

PJM and MISO SCED is based on generation supply offers to sell energy along with non-price responsive load needs and price responsive bids to purchase energy. The RTOs use the voluntary offers and bids along with the load forecast to arrange a security-constrained, economic dispatch for each market interval (normally, every five minutes). The generation supply offers and dispatchable price responsive demand bids will have operating characteristics (e.g., unit ramp rate/load response rates, unit minimum run time/load response durations, etc.,) that the RTO must take into account. PJM and MISO schedule and dispatch generation (and dispatchable demand) in their respective areas using a security constrained dispatch methodology based on the prices and operating characteristics offered by generation suppliers and energy purchases/loads in the region. This methodology is intended to result in the most economic use of resources, as offered into the market, at any given moment, for the entire RTO area, taking into account all system conditions, contingencies, and transmission constraints, while ensuring that sufficient generation is dispatched to meet the energy requirements of the region.

The result of the dispatch is intended to provide reasonably transparent locational marginal prices. LMP defines the marginal cost of serving the next increment of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. During the operating day, resources are called on based upon the economics reflected in their offers. The RTOs strive to dispatch the lowest offer combination of power plants available at any given moment, subject to operational constraints. Generally, however, the highest variable cost unit that must be dispatched to meet load within transmission-constrained boundaries will set the locational market-clearing price for energy in that area. If there are no transmission constraints, LMP will not generally vary across the RTO region (ignoring losses). All sellers in the area receive the clearing price for energy and all buyers in the area that are not bilaterally contracted or self scheduled pay this price. This single clearing price approach to achieving least-cost dispatch will be discussed further in a subsequent section of this report. A balancing market for energy results from this type of LMP-based SCED.

LMPs contain three elements: an energy charge, a congestion charge, and a charge for system energy losses. The energy charge is a single market-clearing price for energy. The market-clearing prices used for settlements will nonetheless differ between some locations whenever there is congestion on the RTO-controlled grid. Prices will also differ between locations due to energy losses. The LMPs for MISO include marginal losses while the PJM currently includes average losses. This difference between the PJM and MISO dispatch practice concerning losses will be discussed later in this report.

The primary means used by PJM and MISO for relieving transmission congestion constraints is by changing the output of generation at different locations on the grid. This re-dispatch could be implemented using non-market procedures such as TLR[25] or market-based procedures such as LMP. However, the market-based LMP approach used by both the PJM and MISO is designed to anticipate and avoid constraints by providing price signals that reflect a measure of congestion costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (re-dispatch) the generation output to serve load, while TLR operates on an engineering-based priority system that does not take economics into account.[26]

The formation of RTOs in the Midwest region with inter-laced seams led the FERC to require PJM and MISO to enter into the JOA to closely coordinate their operations. The two RTOs filed their proposed JOA on December 31, 2003, and it was conditionally accepted by the Commission in March 2004.[27]

Generally, the JOA permits more efficient and reliable system operation, facilitates administration of coordinated markets, and would allow additional utilities to integrate into the PJM markets. The JOA contemplates that the RTOs will progressively integrate their operations. Specifically, the JOA includes, as Attachment 2, a Congestion Management Process, dated April 2, 2004, which outlines specifics of the integration process.

Phase 1 of the JOA provided for coordination of PJM's market-driven operation with MISO's non-market operation prior to MISO's energy market, which was launched on April 1, 2005. Under Phase 2, which applies to RTO-operated LMP-based markets, the two RTOs' additional operational integration includes generation redispatch and coordination to manage congestion; coordination to calculate consistent LMPs; and other actions to which the RTOs agree or that the

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[25] AEP described the TLR feature as follows: "Transmission loading relief is used to ration the transmission capacity when the demand for transmission is greater than the available capacity. The FERC established rules under the open access policy for sale of available transmission capacity (ATC). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded. The TLR process is based on a priority system and does not consider economics." AEP Comments at 6.

[26] At the November 21 Joint Board meeting, Mr. Kruse stated, "We also believe that the LMP pricing strategy allows for the most optimal use of transmission. The old TLR process certainly did not. And I think that shows, if you look at the non-coordinated areas, consistently that still rely on the old TLR process, it's just not the most economic, efficient way to manage congestion." Nov. 21 Tr., at 115.

[27] Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., 106 FERC ¶ 61,251, order on reh'g and clarification, 108 FERC ¶ 61,143, order on clarification and denying reh'g, 109 FERC ¶ 61,166 (2004).

Commission requires.

While this section described the four basic ways that SCED, as operated by PJM and MISO, differs from the general operation of SCED, there are numerous detailed differences (e.g., co-optimization of energy with operating reserves and use of marginal losses). Indeed, many of the RTOs' efforts to continually improve their market design are really just efforts to improve their operation of SCED. This is the case because the RTOs' operation of real-time SCED and their operation of a balancing spot market are really the same thing. This is the principal distinction between the RTOs' SCED operation and traditional SCED operation.

IV. REVIEW OF ISSUES THAT WERE RAISED IN THE JOINT BOARD PROCESS

The issues reviewed in this section of the report were either discussed on the record at one of the two Joint Board meetings, provided in written Comments filed in the Joint Board docket, or provided by PJM or MISO in response to Joint Board data requests.

A. SCED Framework

1. Definition of SCED

The DOE's Report on "The Value of Economic Dispatch" states that the term "economic dispatch" has a common general meaning—"the practice of operating a coordinated system so that the lowest-cost generators are used as much as possible to meet demand, with more expensive generators brought into production as loads increase (and conversely, more expensive generation eliminated from production as load falls)."[28] The DOE states however, that "most people" agree with the definition of the term that is used in EPAct and that was adopted by the Joint Board, namely, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." The DOE's Report did note that several respondents to the DOE's survey suggested that reliability would be better served if the definition referred to "security constraints" rather than "operating limits."[29] The DOE states that the details of how the definition of SCED is put into practice can vary significantly.[30]

2. Efficient Dispatch vs. Economic Dispatch

Concerning economic vs. efficient dispatch, DOE's Report states,

> In a recent hearing of the Senate Energy and Natural Resources Committee, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational

[28] DOE Report at 9.

[29] DOE Report at 49.

[30] DOE Report at 9.

constraints of the generation fleet and the transmission system. Although economic dispatch will usually run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are always used before less efficient units. Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers' electricity costs - for benefits that may not be large enough to offset these additional costs.

- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.

- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives--which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.[31]

MISO's written Comments on this issue state:

> In recent weeks, there has been some discussion about whether the dispatch should be "economic" or whether it should be "efficient." This appears to be a false debate, a red herring based on some unknown confusion. An economic dispatch is an efficient dispatch. An economic dispatch will take into consideration all of the economic and operational factors that affect whether it is more economic to dispatch unit A before unit B or before unit C. In general, a system operator would not consider only a single factor, such as the heat rate of the units, and determine economic dispatch from that factor alone. As between any two units, it is more economic to dispatch a unit with a more efficient heat rate than a unit with a less efficient heat rate, *all other factors being* equal, but all other factors are often not equal. When all economic and operational factors are considered, the unit with the less efficient heat rate may be more or less economic to dispatch at a given moment because of these other factors.[32]

At the November Joint Board meeting, FERC's Mr. Luong explained that efficient dispatch does not take into account as many variables and possible constraints as does economic dispatch such

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[31] DOE Report at 11.

[32] MISO Comments at 7.

that efficient dispatch is a subset of economic dispatch.[33]

AEP commented that, "It should be noted that economic dispatch is not the same as efficient dispatch. Efficient dispatch only considers how well a generator converts the input fuel source into electricity as measured by its heat rate. Economic dispatch improves on efficient dispatch by taking into consideration not only the heat rate but also the cost of the fuel delivered to the plant, the variable cost of operation and maintenance, transmission losses, transmission constraints, etc."[34]

Exelon stated that it wishes to reiterate that

> Security Constrained Economic Dispatch (SCED) is the most cost efficient and effective way of dispatching an electrical system considering transmission constraints and operational limitations on generation, such as ramping limitations, minimum run times, minimum down times, and differing heat rates at different operating levels. For accurate price signals, all system limitations must be accounted for and an accurate load forecast must be included in the economic dispatch. So-called "efficient dispatch," on the other hand, dispatches solely on the basis of the generation units' rated efficiency and ignores other system and unit limitations. So called "efficient dispatch" thereby fails to dispatch on the basis of true economic efficiency. It is only by considering all system and unit limitations that an operator can in fact dispatch most efficiently.[35]

Overall, some people differentiated efficient dispatch from economic dispatch, while others argued that they were the same. A state regulator agreed with DOE that efficient dispatch would probably increase costs to consumers and its benefits are uncertain, but economic dispatch reduces consumer costs and improves wholesale competition.[36]

3. PJM and MISO SCED Technology Tools: Models, Software, and Algorithms

The DOE Report urged examination of the technical quality of current economic dispatch technology tools—software, data, algorithms and assumptions.[37] Accordingly, the Joint Board asked PJM and MISO in a data request to describe their dispatch tools. The response stated that the market applications, including dispatch algorithms, used by PJM and MISO are very similar. MISO's response noted that PJM and MISO share a common vendor for these systems and that vendor delivered systems developed on a common platform. The response stated that, although there are differences between the two markets that are expressed in the dispatch process, the basic mathematical formulation of the SCED function is the same. Significant differences in the

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[33] Nov. 21 Tr., Mr. Luong at 42.

[34] AEP Comments at 5.

[35] Exelon Comments at 1-2.

[36] Chairman Schriber Letter at 1 , and Nov. 21 Tr., Chairman Schriber at 25.

[37] DOE Report at 53.

dispatch process between the two markets involve treatment of losses and ancillary services and these will be discussed in a subsequent section of this report.

MISO states that its entire EMS model covers 21,369 stations and 32,550 buses. PJM states that its network model consists of 6,995 stations and 12,660 buses.

MISO states that its network model contains approximately 94,800 analog telemetry points that are refreshed every 4-30 seconds and approximately 95,800 telemetry status points. In addition, MISO monitors 10,296 thermal facilities (lines and transformers) and 7,931 bus voltages with 6,920 contingency simulations executed approximately every 3 minutes.

PJM states that its network model has 39,000 measurement telemetry points refreshing every 2 to 15 seconds and 35,000 telemetry status points. PJM routinely monitors about 6,000 thermal facilities and 2,000 bus voltages with 4,000 contingency simulations executed every 90 seconds.

The RTOs state that they both use Areva's Unit Dispatch System ("UDS") to conduct real time dispatch. The UDS incorporates various data inputs, including the most recent State Estimator solution, short-term load forecasts, interchange schedule, hydro schedule, generating unit offers, status and ramp capability, and relevant transmission limits based on ongoing security analysis.

4. Locational Marginal Pricing vs. Transmission Line Loading Relief

The primary means used by PJM and MISO for relieving transmission congestion constraints is through LMP. Before market operation, the principal mechanism for managing transmission congestion was TLR. AEP described TLR as follows: "Transmission loading relief is used to ration the transmission capacity when the demand for transmission is greater than the available capacity. The FERC established rules under the open access policy for sale of available transmission capacity (ATC). NERC established the TLR process for dealing with reliability concerns when the transmission network becomes overloaded. The TLR process is based on a priority system and does not consider economics."[38]

However, the market-based LMP approach used by both the PJM and MISO is designed to anticipate and avoid constraints by providing price signals that reflect a measure of congestion costs to market participants. That is, LMPs take into account both the impact of specific generators on the constrained facility and the cost to change (re-dispatch) the generation output to serve load, while TLR operates on an engineering-based priority system that does not take economics into account.

At the November 21 Joint Board meeting, Mr. Kruse stated, "We also believe that the LMP pricing strategy allows for the most optimal use of transmission. The old TLR process certainly did not. And I think that shows, if you look at the non-coordinated areas, consistently that still rely on the old TLR process, it's just not the most economic, efficient

[38] AEP Comments at 6.

way to manage congestion."[39]

Mr. Torgerson stated, "what we found is that prior systems relying on TLRs was inefficient because we'd call TLRs and it led to about a 12 percent under-utilization of the capacity on those constrained flow gates after the TLR was put into effect. With the economic dispatch, we get much closer, right to the edge of how much transmission capacity can actually be utilized."[40]

B. Market-Based SCED

1. Bid-Based vs. Cost-Based SCED

The DOE Report states that "economic dispatch principles and operation are the same in both regulated utility operations and centralized wholesale markets."[41] DOE states that a difference is that "in centralized markets, the merit order of available resources is determined using offer schedules for each resource rather than the variable production costs that are used to dispatch a set of utility-owned resources."[42]

In a data request question, the Joint Board specifically asked PJM and MISO to describe the benefits and detriments of using a bid/offer-based approach to receiving generator offers versus a cost-based approach.[43]

MISO's response to the Joint Board's question is:

> While bid-based and cost-based approaches are often discussed as though they are alternative paradigms, there is in fact only one primary area of difference. Under a "cost-based" approach a central agency or body is assigned the task of determining what an appropriate "cost" is for each generating unit. While it is theoretically possible that these "approved" costs could be updated quickly, in practice it is difficult for the central planner to acquire and analyze the data necessary to perform this calculation. In contrast, under a bid-based regime, competitive forces of the market are relied upon to "drive" bids down to their marginal cost. Since no central authority is required to "approve" the costs, bids can be adjusted quickly to reflect current market conditions.
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> To the extent that an administrative process cannot "keep up with" changing conditions, then we can expect that dispatch under a cost-based approach will be less efficient than that arising from a competitive market driven process. Likewise, to the extent that competitive pressures do not constrain bids to their marginal costs

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[39] Nov. 21 Tr., at 115.

[40] Nov. 21 Tr., Mr. Torgerson at 63.

[41] DOE Report at 4.

[42] DOE Report at 4.

[43] Technically, the term "bid" in this context refers to load/demand bids to purchase from the RTO's market at a particular price or set of prices and "offer" refers to generator/seller offers to sell into the RTO's market at a particular price or set of prices. However, often the term "bid" is used to encompass both "bids" and "offers."

then we can expect that bid-based dispatch will not produce a least cost result.

As a general rule, the longer that "costs" are fixed (because it is costly to review and adjust) we should expect a risk premium and a more expensive result, i.e., if costs are fixed for a year as compared to a month there will be a higher risk premium built into the cost numbers.[44]

PJM's response to the Joint Board's question is:

The fundamental advantage of using bids, rather than "costs," to dispatch the units in the market is that a bid based approach has the benefit of using competitive market [sic] to discipline offers instead of relying on administrative oversight except where specific circumstances require intervention to avoid the exercise of market power. A bid-based approach encourages suppliers to provide alternative offers that may contain more flexible physical operating parameters. This flexibility enhances reliable system operations. The potential challenges with the bid-based approach are that market power could be exercised when the market is restricted to local areas by transmission limitations. In PJM, this challenge is fully addressed because the market design incorporates local market power mitigation rules. Under these local market power rules, generation offers are switched to cost-based offers when market power screening tests detect the potential for the exercises of market power in a localized area.

While a cost-based approach may obviate the need for market power mitigation rules, because all offers are capped at cost, it is unlikely to produce desirable efficiencies and operating flexibility. For example, the cost-based administrative rule approach may incent suppliers to restrict physical generation offer parameters because of concerns that cost-based rules do not permit cost recovery in certain operating modes. This lack of flexibility would reduce the availability of potential dispatch solutions to the system operators, which in turn would adversely affect reliability. Indeed, as data from the PJM Market Monitoring Report indicates the beginning in market operations resulted in a significant decrease in the "forced outage" rate, most apparent during the period from 1996 to 2001, where it fell from about 12% to below 5%. This decline correlated to a time of relative tightness in system wide supply and indicates that generation owners make greater efforts to provide supply in a bid based market. This reflects efficient use of generation.

As reported by the PJM MMU in the 2005 State of the Market Report, these efficiencies have not come at the cost of the exercise of market power. Indeed, as the MMU reports, the energy market, operated on a bid basis, is competitive. In particular, the MMU assessed the price-cost markup in the energy market and concluded that "data on the price-cost mark-up are consistent with the conclusion that PJM Energy Market results were reasonably competitive in 2005."[45]

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[44] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 1.

[45] PJM's March 22, 2006 Response to the Joint Board's March 8 data request question 1.

2. Single Clearing Price SCED Auction vs. Pay-As-Bid Approach

As explained above, traditional individual utility dispatch was done on a unit production cost basis. However, most RTOs , including PJM and MISO, use a bid/offer based auction approach to developing the dispatch stack.

LMP defines the marginal cost of serving the next increment of load at each location, given the dispatch, the constraints binding in that dispatch, and the offers and bids. Generally, the bid of the marginal unit that must be dispatched to meet load within transmission-constrained boundaries will set the locational market-clearing price for energy. All sellers within the constrained area receive this price for energy and all buyers within the constrained area that are not bilaterally contracted or self-scheduled pay this price. Some have wondered how this method of using the bid of the marginal unit to set the market clearing price rather than paying each unit the price it bids can lead to a least-cost result.

In a data request, the Joint Board asked PJM and MISO to describe the benefits and detriments of using a single clearing price market design rather than using a pay-as-bid approach to clearing the SCED spot markets. Both RTOs support continued use of the clearing price approach. PJM provided the Joint Board with a paper written by Dr. Peter Crampton and Dr. Steven Stoft titled "Uniform-Price Auctions in Electricity Markets." MISO's response is representative:

> The merits of clearing price versus pay-as-bid schemes have been carefully considered at every ISO, and there is much literature on the topic. All ISOs have concluded that the clearing price approach is superior. The result is supported by numerous papers and consistently borne out in practice, where several pay-as-bid schemes have been attempted only to discover that they did not function as the promoters anticipated. As a result, the general trend at all ISOs has been to move away from any market rules premised on pay-as-bid approaches and to implement a clearing price approach based on marginal cost pricing.
>
> The allure of a pay-as-bid approach arises from a common assumption that is both incorrect in theory and discredited in practice. The assumption is that if the pricing rule is changed from a clearing price approach to a pay-as-bid approach, generators will not change their bidding behavior. If that assumption were true, then generators with lower costs would consistently bid lower, and loads could capture some benefit by buying power from the generators at their lower bid prices. The assumption is false. Ample experience has shown that if the rule is "the ISO will pay each generator what it bids," then generators will almost invariably change their bids. That is, generators in a pay-as-bid scheme have strong incentives to bid their expectation of what the clearing price would be, rather than to bid their own costs. Using a single market clearing approach will create "rents" for all but the marginal generator. That is, there will be a difference between the market clearing price and the offer of the generator. This difference, which is called a "rent," is in fact payment toward the fixed costs of the generator. Paying the generator for only the variable component of their costs will illicit [sic] one of three types of behavior. They will either (1) raise their offers to include a payment for capital, (2) require a

side payment for fixed costs that will not be included in the energy price and will most likely be a form of uplift or (3) to the greatest extent possible exit the dispatch process itself. None of these behaviors are compatible with the goal of efficiency.

There are many examples of this, particularly in those ISOs that originally used something other than LMP. In California, for example, pay-as-bid rules were used to price energy from plants that were dispatched to relieve congestion. The result was that California ISO experienced persistent "gaming" of bids by generators, because the pay-as-bid scheme created strong incentives to change their bids. In the worst cases, generators expecting to be constrained-off to relieve congestion repeatedly bid negative prices, which forced the ISO to pay extremely high payments to generators not to run. This generator behavior was a logical response by the generators to the pervasive incentives of the pay-as-bid system, which resulted in the ISO paying extremely high constrained-off payments.

In contrast, an approach that pays each generator the clearing price encourages generators to bid their costs, thus facilitating a least-cost dispatch and avoiding the gaming often associated with pay-as-bid schemes. In sum, the assumed benefits of a pay-as-bid scheme are illusory, because the scheme encourages generators to bid something other than their costs. The clearing price approach encourages generators to bid their costs, while facilitating an economic dispatch.[46]

3. Total Revenue Recovered by Generators Through the RTOs' LMP-Based SCED Compared to Aggregate Generator Production Cost

In his January 31, 2006 letter to Commissioner Brownell and filed in Dkt. No. AD05-13-000, Howard Spinner of the Virginia Corporation Commission urged the Joint Board to study "whether MISO/PJM region electric power is being produced in a least-cost manner given the constraints imposed by current system infrastructure."[47] Mr. Spinner expresses a concern that "wholesale electric prices may inappropriately diverge from production resource costs" and that this divergence may ultimately negatively impact retail electricity prices.[48] Mr. Spinner suggests some data and some analysis that could shed light on this issue.[49] This issue was addressed by the Joint Board members at the February 12 meeting.[50] Commissioner Brownell (Chairman of the Joint Board) urged PJM and MISO to "submit data" that "may answer some of these fundamental questions."[51] The RTOs did not provide data pursuant to that request from the Joint Board Chair.

Consequently, in a subsequent Joint Board data request, the RTOs were asked to discuss their position on this issue of potential divergence between aggregate wholesale electric market prices

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[46] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 3.

[47] Howard Spinner Letter at 4.

[48] Howard Spinner Letter at 2.

[49] Howard Spinner Letter at 3.

[50] Feb. 12 Tr., at 43-46.

[51] Feb. 12 Tr., at 46.

that result from RTO-managed SCED and aggregate generator production costs.

MISO's response is as follows:

> In a totally regulated regime, state commissions set retail rates at levels sufficient to recover the total revenue requirements for generation. The total revenue requirements include both "production costs" such as fuel and other variable operating costs, and fixed costs, which include capital costs of construction and maintenance and other ongoing operating costs that are fixed. If the total revenue requirements were not recovered through retail rates, then the utility would face severe financial problems that eventually would make it unable to continue reliable service in the short run or maintain adequate resources in the long run.
>
> In a market regime, an analogous principle applies. Market prices must recover both production costs and fixed costs. If market prices were artificially restricted to cover only the production costs, the fixed costs would not be recovered. In that case, market investors would refuse to build new facilities or maintain existing plants because they would know that their fixed costs could not be recovered.
>
> ISOs pay generators a "clearing price" based on the marginal costs of the dispatch. The marginal cost is not the "production cost" of each unit; it is, instead, the marginal cost of the marginal unit (or units) needed in the dispatch. The effect of using marginal "clearing price" approach is that over time, the combined set of clearing prices will recover both the "production costs" of generators and their fixed costs, just as would occur in a fully regulated regime. Similarly, just as retail rates in a regulated regime must recover the full revenue requirements, including both production and fixed costs, market prices must recover the full revenue requirements of the plants needed for dispatch. In turn, retail rates should reflect the full revenue requirements, whether in a regulated or market system.[52]

PJM's response to the data request is lengthier than MISO's. In general, PJM's response refers to a number of indicators in PJM's State of the Market Report that discount the hypothesis of divergence between wholesale electric market prices and generator costs as a result of SCED in the PJM marketplace. PJM states that the real issue is whether the units setting prices in PJM are doing so based on offers that include significant mark ups over marginal costs. PJM cites numerous measures in its State of the Market Report to show the contrary.[53]

4. Marginal vs. Average Losses in the Dispatch

The Joint Board notes that MISO uses marginal losses in its dispatch but PJM uses average losses. In a data request, the Joint Board asked the RTOs the following question:

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[52] MISO's March 22, 2006 Response to the Joint Board's March 8 data request question 2.

[53] PJM's March 22, 2006 Response to the Joint Board's March 8 data request question 2.

Please describe the benefits and detriments of using marginal, rather than average losses, in the dispatch. How does the approach used affect the resulting dispatch? How does PJM's practice of using average losses affect the interface with the MISO market, which uses marginal losses?

Each RTO's response to this question was basically the same as follows:

A marginal loss approach models the incremental increase or decrease in transmission losses that occur with incremental changes to the economic dispatch pattern. The average loss approach does not account for this incremental loss effect. The marginal loss approach is more efficient because it tends to minimize system losses as part of the dispatch algorithm which in turn minimizes the overall cost to serve load. PJM performed annual production cost analysis to evaluate the benefits of the marginal loss approach over the current average loss approach. The results of this analysis indicated that the annual production cost savings under the marginal loss approach was approximately $100 million across the entire market. The analysis indicated that the production cost savings under marginal loss-based dispatch were a result of a decrease in hourly system losses and a decrease in transmission congestion caused by the more efficient generation dispatch patterns to serve the hourly demand. However, while marginal loss implementation does increase market efficiency, certain practical implementation issues do exist with the marginal loss approach. The marginal loss impacts on locational pricing result in the need to develop allocation rules to distribute marginal loss revenues. The development of these business rules has created considerable debate in the RTO stakeholder process because of concerns with cost shifting versus the current approach. The current markets have also not developed marginal loss hedging products. These issues are not insurmountable but their resolution has created implementation complexities in RTOs where marginal losses have been implemented and has created considerable debate in the PJM stakeholder process.

The PJM/MISO market to market coordination process has worked well in providing coordinated transmission congestion management between the PJM and MISO markets. Therefore, PJM does not believe the difference in the loss models between the RTOs has adversely impacted interregional transmission congestion coordination. However the difference in the transmission loss pricing may have a small impact on price convergence between the markets. Since marginal loss pricing is a relatively small impact compared to congestion pricing, the impact is limited.

One of PJM's members has filed a complaint with FERC concerning PJM's treatment of marginal losses (FERC Dkt. EL06-55-000).

5. Transmission Ancillary Services Within SCED

SCED must take into account ancillary services such as downward-and-upward regulating margin requirements of the system and operating reserves.

In response to a Joint Board data request, the RTOs state that because the former control areas that make up the MISO footprint are still independent Balancing Authorities within the MISO market, MISO does not centrally dispatch the Regulation or Spinning Reserve services. Rather, each individual Balancing Authority is responsible for assigning the required amount of Regulation and Spinning Reserve within its area, and directing the deployment of those services based on its individual area control error ("ACE"). Each Balancing Authority calculates its own Regulation signal that is used to deploy the Regulation each assigns within its own area, and each Balancing Authority is responsible for responding to system disturbances. The individual Regulation and Spinning Reserve assignments made by the individual Balancing Authorities are communicated back to the MISO control center for inclusion in the UDS economic dispatch solutions. MISO states that development of an ancillary services market is underway with active participation from stakeholders in the Ancillary Services Task Force.

The RTOs state that PJM operates markets for both regulation and operating reserves. In order to account for the product substitution cost associated with their provision, the PJM ancillary service optimization software co-optimizes Regulation and Spinning Reserve with energy to assign the most cost-effective resources throughout the market to provide the services. These assignments are then fed into the UDS application such that they are respected in the economic dispatch solution. PJM is a single Balancing Authority with a single ACE. PJM therefore calculates a single Regulation signal based on a filtered value of that ACE that is used to deploy the Regulation assigned to individual units, and also deploys Spinning Reserve in response to system disturbances on an RTO-wide basis.

C. SCED Benefits

1. Quantifying the Benefits of SCED

At the first joint board meeting, both PJM and MISO presented data from several studies to show both qualitative and quantitative benefits of SCED.[54] Various entities questioned the studies and data used by PJM and MISO to reach their conclusions. The Wisconsin load serving entities argued against using MISO's March 26, 2004 study of savings in Wisconsin claiming it was flawed and suggested developing more accurate studies.[55] Chairman Jergeson also cautioned that the studies alleging net benefits due to the implementation of regional markets by PJM and MISO were offered in macro, region-wide format, often based on economic modeling rather than actual experiences.[56] His concern was that these studies failed to disclose the distribution of benefits and costs, both geographically and demographically.[57] The issue of benefit recipient was extensively discussed at the February 12 Joint Board meeting with distinctions made between the customer perspective and the generator perspective.[58] The effect of retail

[54] Nov. 21 Tr., Mr. Harris at 43-58 and Mr. Torgerson at 58-69.

[55] Wisconsin Load Serving Entities ("WLSE") Comments at 4-5.

[56] Nov. 21 Tr., Chairman Jergeson at 2.

[57] Nov. 21 Tr., Chairman Jergeson at 2.

[58] February 12 Tr., at 23 and 37.

ratemaking on the issue of benefits pass-through was discussed with speakers noting that many state ratemakers have authority over the reflection of off-system sales revenue as offsets to retail rates and the retention of in-state low cost generation benefits for in-state ratepayers.[59]

Most entities, including DOE and state regulators, noted the importance of credible studies that seek relevant information and use accurate data to determine the benefits and costs of SCED as conducted by PJM and MISO, understand the current market conditions and improve market performance.[60] Commissioner Hadley recommended that DOE, RTOs and the joint board members work together to come up with the questions that need to be asked and answered to study the benefits of SCED.[61]

2. The Effect of the RTO Spot Markets on Forward Bilateral Contracting

In their paper, "Uniform-Price Auctions in Electricity Markets," Drs. Cramton and Stoft emphasize the importance of forward bilateral contracts as a method to reduce price risk for both suppliers and consumers.[62]

In his remarks to the November 21 Joint Board meeting, Mr. Collins of Alliant Energy stated that, since the MISO real-time and day-ahead markets have begun operations, bilateral transactions have "shrunk considerably."[63] However, Mr. Orr of Constellation Energy remarked on the transparency of the RTOs' real time markets and described that one of the benefits of this is providing information so that market participants can decide "on an economic basis, how to deploy your assets and manage the risks for your constituency" and how to "manage risk forward off of that information."[64] Because of the importance of forward contracting and the apparent inconsistency of the two statements of the Joint Board witnesses, the Joint Board asked PJM and MISO a data request question about the impact of their day-ahead and real-time energy markets on the willingness and ability of market participants to bilaterally forward contract.

MISO responded by stating that,

> The MISO market tariff accepted by FERC accommodates bilateral transactions through certain provisions that allow market participants to schedule bilateral transactions through the energy markets. The duration, terms and conditions of such bilateral agreements are negotiated between market participants without involvement of MISO. As such, market participant performance with respect to

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[59] February 12 Tr., at 39.

[60] Wisconsin Load Serving Entities ("WLSE") Comments at 4, Nov. 21 Tr., Mr. Meyer, Tr., at 23 (discussing the limitations of using the existing studies), questions from Chairman Davis, Commissioner Chappelle, Chairman Hardy and Commissioner Wefald answered by Mr. Harris and Mr. Torgerson on the studies used by PJM and MISO, Nov. 21 Tr., at 76-85.

[61] Nov. 21 Tr., Commissioner Hadley at 107-108.

[62] This paper was provided to the Joint Board by PJM in response to Question #3 of the Joint Board March 8, 2006 data request. See, e.g., page 6 and 11 for a discussion of the importance of forward contracting.

[63] Nov. 21 Tr. ,Mr. Collins at 113.

[64] Nov. 21 Tr., Mr. Orr at 134.

bilateral forward contracts is largely addressed by the parties to the agreement. In general, over 90% of all energy traded in the real time energy market is either pursuant to a bilateral contract between market participants or has cleared the day-ahead energy market.

PJM responded that,

> Every indication is that bilateral forward contracts have remained the main form of supply used to meet load obligations in PJM. This is supported by a growing rather than lessening volume of "bilateral eSchedules" used by market participants to settle through PJM the transfer of energy they agreed to buy or sell outside PJM's short run markets.
>
> At a more general level, PJM's transparent spot and day-ahead market prices provide the basis for most forward contract indexes in use today. Prior to the creation of these short term markets, participants would have had little independent basis for developing a forward price estimate for contracting purposes.
>
> As stated in the 2005 State of the Market Report, PJM does not have access to data that would allow PJM to accurately measure the amount of energy settled in our real-time market that has a forward hedging contract covering exposure to real-time prices. While some portion of the energy is certainly unhedged "balancing," large portions are likely hedged directly through physical bilateral contracts or financial derivative contracts.

3. Reliability

MISO stated that,

> The manner in which the system operator dispatches generators ensures that the grid is operated safely and reliably. Hence, an important starting point is to clarify that the dispatch is an essential reliability function; it is not an option or a policy choice. Every modern electricity system maintains reliable operations through its dispatch.[65]

MISO further stated that, "To ensure reliable operations the dispatch must be 'security constrained.'"[66] Mr. Torgerson added that reliability is aided by MISO's regional coverage.[67]

Mr. Harris stated that PJM is more reliable now that it is also the market operator than it was before it began operating markets.[68]

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[65] MISO Comments at 2.

[66] MISO Comments at 2.

[67] Nov. 21 Tr., Mr. Torgerson at 65.

[68] Nov. 21 Tr., Mr. Harris at 100.

Reliability was generally discussed in the Joint Board process in the context of discussing other matters, rather than as a particular focus of inquiry. For example, AEP stated that "Reliability is driven by the ability of the transmission system operator to understand the limitations of the transmission network and model these limitations in the transmission security analysis process."[69]

D. SCED Scope

1. Geographic Scope of SCED

The DOE Report looks into the question of how large a dispatch area should be. The DOE's Report states,

> the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers.[70]

The DOE Report also states that "economic theory suggests that the sum of separate cost-minimizing dispatch solutions for several independent but adjacent dispatch regions is likely to be larger than the cost-minimizing solution that would result if the entire area were combined and dispatched as one integrated system."[71] The DOE Report suggests that this is a mathematical issue of local versus global optimization or cost-minimization.[72] The DOE Report further states that a larger economic dispatch area "allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs."[73] The DOE Report states that, as an operational matter, "the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and easily."[74] DOE's speaker at the Joint Board meeting confirmed that DOE found that economic benefits tend to increase as the geographic scope and electrical diversity of the area under unified dispatch increases.[75]

AEP stated that, "In theory and practice as the size of the RTO/control area increases more resources (generation and transmission) are available under one control center to enhance the overall economic dispatch process. These additional resources allow for a more economic dispatch over the larger area, rather than separate multiple area dispatches, reducing transactional friction and more efficiently managing transmission congestion. This facilitates the determination of the opportunity cost of transmission, which depends critically on the marginal

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[69] AEP Comments at 10.
[70] DOE Report at 27.
[71] DOE Report at 28.
[72] DOE Report at 28.
[73] DOE Report at 28.
[74] DOE Report at 28.
[75] Nov. 21 Tr., Mr. Meyer at 21.

cost of power at different locations, and these costs are determined simultaneously with the dispatch."[76]

At the November Joint Board meeting MISO's Mr. Torgerson stated, "the optimization of dispatch across a wider region does lead to a more economic use of resources."[77] Mr. Torgerson also stated that every few seconds MISO looks at the 180,000 data points that are integrated into MISO's state estimator. PJM's Mr. Harris stated, "the technology is allowing these synergies to grow and develop because you have the large regions and you have the capability to do that."[78] Mr. Harris also stated that, with a new control center, PJM is looking at running a state estimator for the entire Eastern Interconnection.[79]

The concept of having a single dispatch across the combined PJM and MISO geographic areas was discussed at the November 21 Joint Board meeting.[80] Mr. Torgerson stated that the costs of taking that step might be prohibitive and referred back to the preliminary cost analysis done for the RTOs' joint and common market filing.[81] Mr. Harris suggested that the analysis of contingencies for a combined dispatch might create a significant data problem.[82]

The Joint Board notes that PJM and MISO have committed to conducting a cost/benefit analysis of a combined dispatch across the PJM/MISO geographic area.[83]

AEP stated that there are advantages and disadvantages to increasing geographic scope of SCED as follows,

> Advantages – *Theoretically,* the entire interconnection would provide the highest level of reliability and lowest cost over the entire region. Disadvantages – Due to technology limitations (such as limited theory on how to control and monitor large systems, need for infrastructure enhancements and mathematical problem formulation and algorithmic computational capability), it is not possible today to model and computationally solve the security constrained economic dispatch in real-time. The problem becomes more complex the bigger the control area becomes. The inability to solve the security constrained economic dispatch could reduce reliability and increase cost due to infeasible solutions.[84]

The Joint Board notes that the RTOs' common market filing states that "a single market encompassing an area with a peak load of over 247,000 MWs, may not be technologically

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[76] AEP Comments at 7

[77] Nov. 21 Tr., Mr. Torgerson at 61.

[78] Nov. 21 Tr., Mr. Harris at 51.

[79] Nov. 21 Tr., Mr. Harris at 55.

[80] Nov. 21 Tr., at 89-92.

[81] Nov. 21 Tr., at 91 referring to the RTO's October 31 filing in Dkt. No. ER04-375-017/ER04-375-018.

[82] Nov. 21 Tr., Mr. Harris at 92.

[83] See e.g., the RTOs' February 28, 2006 filing in Docket. No. ER04-375-017/ER04-375-018 at 7.

[84] AEP Comments at 8

feasible at this time."[85] However, the RTOs' common market filing provided no support for that statement. Accordingly, in a data request in the instant proceeding, the Joint Board specifically asked the RTOs what additional capability would be needed for their respective existing modeling and dispatch systems to handle additional generation and load. The RTOs responded that their existing systems could handle a 1,000 MW increase with no upgrades. Both RTOs responded that an increase of 50,000 MW of load and generation would require upgrades in computing capability and data storage capability. Both RTOs declined to speculate on the technological feasibility of managing increases in the magnitude of 100,000 to 150,000 MW without a more thorough technical evaluation.

A utility commenter suggested conducting a study to highlight the results and benefits of increasing generator competition over as wide an area as physically possible by increasing transmission capacity.[86]

2. PJM/MISO Common Market Issues

Some state regulators are concerned that if FERC allows PJM and MISO to continue proceeding down divergent market design paths, it will create difficulty for market participants seeking to operate in both PJM and MISO and perpetuate seams issues that negatively impact the market.[87] They recommended that any initiatives pursued by PJM or MISO should contribute to the development of a joint and common market, and FERC should make sure that any initiative that is an exception to this goal should include a clear explanation of how long any short-term necessary incompatibility would last.[88] Several commenters stated that a number of issues needed to be addressed by PJM and MISO in order to optimize SCED.[89] These issues include: a PJM/MISO joint and common market; a consistent PJM/MISO resource adequacy requirement; a consistent PJM/MISO long-term planning system to ensure a vibrant transmission grid; unified allocation of Firm Transmission Rights/Auction Revenue Rights; the development of compatible or unified ancillary service markets; and identifying differences in algorithms between PJM and MISO dispatch mechanisms.[90] There is concern that the duplicate RTO structures within Ohio and the lack of a common geographic footprint in the state for transmission matters as well as wholesale market transactions impedes SCED.[91]

Chairman Schriber asserted that different operational rules and business practices in PJM and MISO have stifled transactions with neighboring utilities across these RTO borders.[92] He

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[85] RTOs' October 31 filing in Docket. No. ER04-375-017/ER04-375-018 at 45.

[86] AEP Comments at 2.

[87] Comments of the Joint State Commissions in Dckt No. AD05-13 (Joint State Commission Comments) at 3-5 and 13.

[88] Joint State Commission Comments at 5.

[89] Joint State Commission Comments at 5, WPSRC Comments at 4-5, Nov. 21 Tr., Mr. Torgerson at 105 and Mr. Orr at 137-138.

[90] Joint State Commission Comments at 5, WPSRC Comments at 4-5, Nov. 21 Tr., Mr. Torgerson at 105 and Mr. Orr at 137-138. *See also* Nov. 21 Tr., Mr. Meyer at 29, and Mr. Orr at 130-131.

[91] Chairman Schriber Letter at 1.

[92] Chairman Schriber Letter at 2.

recommends that each RTO's operational rules and business practices must be reviewed and amended to recognize and accommodate cross RTO border trading if separate SCED is to facilitate an open and common market in the combined PJM/MISO region.[93]

It was also suggested that joint and common planning is needed to help address the loop flows that the dispatch of one system creates on the other.[94]

E. Transmission Infrastructure

1. The Importance of Adequate Transmission Capacity

The DOE Report identifies a number of "conditions that could exclude a resource from the dispatch stack."[95] One of those conditions is the "configuration of the existing transmission system."[96] The DOE states that,

> The existing transmission system's configuration limits the ability of dispatchers to accommodate additional generation from units located in certain transmission constrained locations within the system. In many cases, expanded transmission capacity will increase the deliverability of output from efficient generators to loads. But in many areas there are delays in building new transmission capacity that would reduce congestion and enable greater transmission flows.[97]

The DOE Report further states,

> Transmission adequacy affects how much generation can flow and how much grid reliability concerns will constrain different generation production and deliverability patterns. Easing key transmission constraints improves access to load for almost every generator as well as improving grid reliability. Therefore many respondents [to DOE's survey] reiterate the importance of enhanced transmission planning processes that address long-term economics as well as reliability, and of building a more robust transmission network that will enable customers to save money by reliably accessing more efficient generation than is possible with today's transmission system.[98]

AEP stated that, "Transmission constraints are the primary obstacle to minimizing the overall supply cost. Reliability is driven by the ability of the transmission system operator to understand

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[93] Chairman Schriber Letter at 2.

[94] AEP Comments at 9 and Chairman Schriber Letter at 2-3 (loop flows can produce congestion on the neighboring system, requiring more uneconomic (out of merit order) dispatch to overcome the loop flow effects, e.g., the Lake Erie loop flow.).

[95] DOE Report at 45.

[96] DOE Report at 46.

[97] DOE Report at 46.

[98] DOE Report at 50.

the limitations of the transmission network and model these limitations in the transmission security analysis process."[99] AEP also stated that, "The key to optimizing the economic dispatch and maintaining reliability is a robust transmission network. Investments in the transmission grid targeted at relieving transmission bottlenecks will not only improve reliability but will do more than any administrative change to help ensure that low cost generation will be fully utilized in the economic dispatch process."[100]

Several parties in the Joint Board process argued that a robust transmission network is the key to optimizing economic dispatch and ensuring dispatch and delivery of a low cost reliable supply of energy.[101] Commissioner Nickolai made the point that, although security constrained economic dispatch may be an efficient method of allocating scarce transmission resources, "if all we had was scarcity what we're going to see is prices that can just go up and up and up."[102]

Even in an RTO that enables all generation to bid into the market, transmission bottlenecks can and do limit the amount of low-cost energy that flows through to load. Under these circumstances, the dispatcher will necessarily redispatch out of merit (more expensive) energy from a local source to manage the congestion.[103] Therefore, without adequate transmission, lower cost generation will not displace higher cost generation to its full potential.[104] Some Joint Board participants, including Commissioner Butler, argued that constrained areas or load pockets such as the State of New Jersey need investments in transmission and generation to relieve the constraint and improve reliability and improve the "security constrained" part of economic dispatch.[105]

Some parties asserted that in order to get transmission built, long-term regional transmission planning, timely investment and cost recovery, and appropriate cost allocation are needed.

2. The Transmission Planning Process

Several commenters argued that a regional and long-term transmission planning process is necessary to build a robust transmission network.[106] One commenter recommended implementing a collaborative and inclusive transmission planning process for local transmission owners and wholesale transmission customers for reliability-based upgrades and economic

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[99] AEP Comments at 6.

[100] AEP Comments at 6.

[101] Chairman Schriber Letter at 1 and 3, AEP Comments at 6 and 10, ITC Comments at 2-3, WPSRC Comments at 6, Mr. Tatum at 1 and Nov. 21 Tr., at 144, and Nov. 21 Tr., Mr. Welch at 152 and 155.

[102] February 12 Tr., at 69.

[103] Mr. Tatum Comments at 1, ITC Comments at 3 and Joint State Commission Comments at 9. Joint State Commissions include Delaware Public Service Commission, District of Columbia Public Service Commission, Illinois Commerce Commission, Kentucky Public Service Commission, Michigan Public Service Commission, New Jersey Board of Public Utilities, Public Utilities Commission of Ohio, Pennsylvania Public Utility Commission and Public Service Commission of West Virginia.

[104] WPSRC Comments at 6, Nov. 21 Tr., Mr. Tatum. at 144, and Mr. Welch at 152 and 155.

[105] New Jersey Board of Public Utilities (NJBPU) Comment at 2.

[106] Joint State Commission Comments at 10, NJBPU Comments at 2 and 6, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 145, and Mr. Naumann at 166.

upgrades.[107] Another commenter contended that a properly executed consistent regional transmission planning process over a large geographic area, including siting and appropriate cost allocation for needed upgrades to the transmission system, is needed.[108] Other entities argued that PJM and MISO's long-term planning needs to be coordinated and done jointly to ensure an adequate transmission grid to optimize the ability of SCED in LMP markets.[109] One commenter argued that both RTOs conduct separate planning and that MISO's long-term planning is inadequate because it aggregates the plans of the transmission owners within its footprint and fails to include transmission projects by entities other than the transmission owners in its footprint.[110] MISO admitted that it needs to improve its long-term transmission planning and procedures.[111] While a state commission supported SCED and transmission planning, it argued that SCED should not solely dictate the transmission planning process. Instead, additional costs and benefits that are not accounted for in SCED must be addressed in the transmission planning process.[112]

Mr. Torgerson stated that, "We need long term transmission plans and we need to put the procedures in."[113]

3. Cost Recovery for Transmission Investments and Transmission Pricing/Cost Allocation

Mr. Harris emphasized the importance of transmission cost allocation.[114]

Commenters suggested that, in order to build transmission infrastructure, timely investments in the transmission grid are needed.[115] Some market participants desire more assurance with respect to cost recovery and cost allocation to provide new facilities.[116]

One commenter argued that the existing MISO transmission pricing proposals discourage generation and transmission construction, thus hampering the optimization of SCED.[117] It was

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[107] Nov. 21 Tr., Mr. Tatum at 145 and Comments at 2.

[108] Joint State Commission Comments at 10.

[109] Joint State Commission Comments at 10, WPSRC Comments at 2 and 6, Chairman Schriber Letter at 3, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 144 and Mr. Welch at 152.

[110] WPSRC Comments at 6.

[111] Nov. 21 Tr., Mr. Torgerson at 98.

[112] NJBPU Comments at 2 and 6. For instance, it suggests examining the cost of environmental and health impacts of emissions from coal burning plants that will be used to provide lower cost power. NJBPU at 3. In another example, NJBPU argues that its investment in cleaner technology will be undermined because coal-fired plants with advanced pollution control technology or plants fueled by natural gas will produce energy at a higher cost and thus be dispatched after a less expensive plant such as a coal-fired plant without advanced pollution controls. NJBPU Comments at 4.

[113] Nov. 21 Tr., Mr. Torgerson at 98-99.

[114] Nov. 21 Tr., Mr. Harris at 104.

[115] Joint State Commission Comments at 9, Mr. Tatum Comments at 2, ITC Comments at 4 and AEP Comments at 6 and 10. *See also* WPSRC Comments at 5-6, Nov. 21 Tr., Mr. Harris at 105, Mr. Welch at 169 and 173.

[116] Nov. 21 Tr., Mr. Harris at 103-104, Mr. Welch at 153 and 167-173.

[117] WPSRC Comments at 6.

recommended that transmission investment could be spurred by using formula rates, making transmission less risky, and creating state and Federal partnerships to build interstate facilities, and applying regional rates to regional transmission.[118] Others proposed flow-based pricing, but that may require considerable study and testing, and so, in the meantime, FERC should consider distance pricing mechanisms to replace license plate rates to more closely reflect the nature of the commerce being conducted on the interstate system.[119] Another commenter asserted that using postage stamp rates would provide incentives for generation and transmission investment.[120]

Chairman Schriber suggested that if non-incumbent merchant transmission owners built transmission additions, they should be allowed to recover their costs in the RTO's tariff on the same non-discriminatory basis as provided to generation-owning transmission companies.[121]

Commissioner Ervin mentioned SPP's FERC approved transmission cost allocation approach.[122]

4. Independent Transmission Companies

Some parties suggest that independent transmission companies (transcos) could help achieve the objectives of economic dispatch by improving transmission infrastructure and that the value of for-profit transcos needed to be recognized in the joint planning efforts by PJM and MISO.[123] A transco noted that as long as ownership of the transmission grid remained in the hands of generation owners protected by its congestion, the benefits of SCED could not be fully achieved because of constraints resulting in intra-market price differentials.[124] Some parties asserted that FERC and RTOs, with the assistance of state regulators, must develop the most efficient delivery routes to serve load and then allow existing transmission owners, merchant transmission developers, and for-profit transcos to bid on construction and ownership of transmission facilities.[125]

F. Effects of SCED on Generators

1. Participation by Non-Traditional Generation in SCED

Certain participants asserted that opportunities for non-traditional resources such as wind power

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[118] Nov. 21 Tr., Mr. Tatum at 146 and Comments at 2, Mr. Welch at 170, ITC at 4, and Mr. Harris at 104.

[119] Chairman Schriber Letter at 4.

[120] WPSRC Comments at 6.

[121] Chairman Schriber Letter at 2-3.

[122] Nov. 21 Tr., Commissioner Ervin at 176.

[123] ITC Comments at 1 and Chairman Schriber Letter at 2-3.

[124] Chairman Schiber Letter at 2.

[125] Chairman Schriber Letter at 4 and ITC Comments at 3.

to participate and compete equally with traditional resources such as fossil-fueled generation should be further explored and promoted.[126] They suggested that FERC should encourage the utilization and sharing of resources and the use of new technology and methods to analyze and incorporate the benefits of diversity of generation and load to drive down costs.[127]

2. Generation Fuel Diversity

Chairman Schisler raised the issue of generation fuel diversity and requested the panelists at the Chicago meeting to comment on this issue.[128] Mr. Harris responded that PJM, as the operator of the market, is "agnostic" as to generator fuel type.[129] Mr. Harris went on to explain that, in practice, the RTOs' market transparency has improved generator diversity with "green" sources becoming more significant.[130] Mr. Harris also mentioned the importance of state planning.[131]

3. The Incorporation of Low-Cost Generation Areas Into Regional SCED

Chairman Jergeson cautioned against changing the way Montana Dakota Utilities, the rural electric cooperatives, and WAPA serve the customers in eastern Montana.[132] He noted that over the years, these entities have demonstrated that they are capable of delivering comparatively low-cost electricity and no harm is occurring that needs to be fixed by a FERC/MISO/PJM fix. His recommendation was that SCED may be applied to the offers for sale of surplus power only after entities have satisfied their native load obligations.[133]

Mr. Torgerson addressed this issue as follows:

> They're not necessarily paying the LMP price for every transaction that occurs. I mean, the LMP price is usually just paid on the imbalance or on a very small amount of the transactions that happen. And in your state, I mean, you still have vertically integrated utilities, and you have, as state commissioners, you can determine, you know, what gets passed through to customers from your costs and from your generation, from the generation that they do. They're offering it into the market and we're dispatching it at $20. If they are offering it at $20, that's always something you've got to make sure that, you know, look at what they're really offering, and then their generators are going to run. They're going to have the power there and some of it is going to be exported. So, you'll have all that data and

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[126] Joint State Commission Comments, at 12.

[127] Joint State Commission Comments, at 12-13.

[128] Nov. 21 Tr., Chairman Schisler 132.

[129] Nov. 21 Tr., Mr. Harris at 86.

[130] Nov. 21 Tr., Mr. Harris at 87.

[131] Nov. 21 Tr., Mr. Harris at 87.

[132] Chairman Jergeson Comment at 1.

[133] Chairman Jergeson Comment at 1-2 (objecting to the application of economic dispatch that would require load serving entities to dispatch their lower cost generation into the regional market, but serve their own customers with higher cost regional market price).

information on what is actually being done. And then, as regulators, you know, you will look at all this information to determine what is appropriate in your state.[134]

G. Other SCED Issues

1. Demand-Side Participation in SCED

Some observers say that operators of the organized markets must develop more ways for demand-side response to participate in the dispatch.[135] Mr. Harris stated that it is important "how do we get, we truly get [ ] demand side functional and I really think that the [end]-state will be demand that can participate in the economics or real time dispatch. But each state has different rules in retail, different rules how demand would work, net metering rules. You know, how to really concentrate in that area so that we can really get the consumer participating in the economic value of the dispatch equation. And it almost has to be state by state but to the degree we get commonality in moving that forward and get a healthy, robust demand programs moving, we'll be much better served quicker and it solves a host of other issues when you get that into play."[136] Mr. Kruse agreed that "demand side management is certainly the forefront of the future for, for a lot of reasons."[137]

According to some state commissions, in order for demand response to fully participate in wholesale markets, considerable work is required to develop effective demand response programs, secure transmission owner, load serving entity and state regulatory support for those programs and build customer understanding and participation.[138] Commissioner Wright suggested that the Joint Board should address demand response as a potential competitive factor in the report that it provides to the Commission.[139] MISO noted that it should increase demand side participation in SCED in order to balance the supply side.[140] PJM has played a role in programs that foster demand response and distributed generation.[141]

Mr. Torgerson stated that MISO needs to "continue working on the ability for demand side to participate in the dispatch equation. There's some wonderful technologies on demand side. The opportunities are huge. The capabilities are there with the technology and, and the sooner we can

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[134] Nov. 21 Tr., Mr. Torgerson at 95.

[135] Nov. 21 Tr., Mr. Torgerson at 98, Mr. Harris at 54 (PJM has seen benefits of demand response) and 104, and Mr. Kruk at 149.

[136] Nov. 21 Tr., Mr. Harris at 104.

[137] Nov. 21 Tr., Mr. Kruse at 119.

[138] Joint State Commission Comments at 10.

[139] Commissioner Wright Comment.

[140] Nov. 21 Tr., Mr. Torgerson at 98.

[141] The Joint State Commissions note that PJM has participated in programs that have encouraged several states to develop common rules and programs for demand response and distributed generation interconnection and integration. Joint State Commission Comments at 11. Other programs that identify and factor the environmental value of a particular generator into a buying decision helped states in the PJM region to ensure dispatch of cleaner generation. Joint State Commission Comments at 11.

get demand side to fully participate in the economics of the dispatch, the better we're going to be and it will really balance out the supply side devices."[142]

2. Accuracy of Data Input Into the Dispatch

The accuracy of data inputs into the dispatch is important. For example, Exelon stated:

> Ensuring to the maximum degree that dispatch assumptions are accurate is crucial to maximizing the benefits of SCED. If dispatch assumptions are not accurate or if the system operators do not commit and de-commit available generation appropriately, some of the benefits of economic dispatch are lost through out-of-market actions taken by PJM and MISO. For example, consistently over-committing generation or not releasing generation from the dispatch queue when it is no longer needed tends to skew the results of economic dispatch by shifting cost recovery out of the transparent economic dispatch price signals into non-transparent uplift costs commonly called operating reserve charges (PJM) or revenue sufficiency guarantee (MISO). Such out-of market actions, while sometimes necessary to preserve reliability and/or mitigate local market power, must be carefully monitored to ensure that appropriate price signals are sent to the market. Skewed price signals affect both the real time market and the longer-term forward bilateral market, and will result in increased total market costs over time.[143]

Similarly, DOE's Mr. Meyer stated that, "the economic dispatch is very dependent on the accuracy of load forecast[s]. And improvements in the accuracy of such forecasting will, by themselves, lead to improvements in the efficiency of economic dispatch."[144] DOE's Report states, "load forecasting is an unappreciated element of the dispatch challenge. Improving the quality of load forecasting will lead to improvements in both the reliability and cost-minimization impacts of economic dispatch."[145]

It was observed that improved forecasting by RTOs and market participants could bring further operational benefits.[146]

3. The Effect of Independence of the RTOs on Confidence in the RTOs' Market-Based SCED Process

At the November 21 Joint Board meeting, Mr. Kruse observed, "There's two key components that both of them [PJM and MISO] share. They're independent and they're transparent. Those

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[142] Nov. 21 Tr., Mr. Torgersonat 98-99.

[143] Exelon Comments at 4.

[144] Nov. 21 Tr., at 26.

[145] DOE Report at 51.

[146] Nov. 21 Tr., Mr. Meyer at 26, Mr. Kruse at 118 (important that day ahead plans mirror real time plans as closely as possible), and Joint State Commission Comments at 10.

are the two key things from an independent participant that we expect in a market that helps make it work right, it helps us have confidence that the market's done the most economical way with no favorability to any of the other participants. Those are key in what makes the economic dispatch decisions work right."[147]

At the February 12 meeting, Commissioner Nickolai suggested that the Joint Board "review the governance of the RTOs to help assure that they truly are independent, to the extent that we can make them independent operators of the markets and the grid."[148] He raised a question about "the extent to which they are dependent actors versus the extent to which they feel that they must be agents of their members and transmission owners."[149] He stated that the assurance of independence is an important foundation for "confidence that the grid and the markets are going to be operated in a manner fully consistent with the goal of maximizing the economic benefit to the public."[150]

V. RECOMMENDATIONS OF THE JOINT BOARD FOR THE PJM-MISO REGION

The previous Sections of this report reviewed issues that were raised in the Joint Board process. Those sections are intended to be presented objectively. The discussion in those sections is intended merely to review and summarize material that was discussed at the Joint Board meetings; submitted in the Joint Board docket; provided by the DOE; or provided by MISO or PJM in response to a Joint Board data request.

As we were invited to do by Section 1298 of EPAct, we considered "issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned."[151] In contrast, this Recommendations section is not intended merely to be a review. Rather, it is a policy section designed to capture the majority views of the Joint Board members "and to make recommendations to the Commission regarding such issues" as invited by Section 1298 of EPAct. While we strove for consensus, not all Joint Board members agree on all aspects of this report or on all aspects of these recommendations. In particular, some Joint Board members believe that some aspects of these recommendations may be outside of the narrow scope of the *process* of security constrained economic dispatch and some Joint Board members believe the recommendations should remain within that scope. Accordingly, nothing in this report should be interpreted as being binding on individual Joint Board members or their respective agencies or preventing such members or agencies from taking positions that deviate from those adopted in this report should circumstances warrant.

In crafting the recommendations below, we are guided by our Joint Board Chairman, Commissioner Brownell, to strive for ways to ensure that SCED will enhance the reliability and affordability of service and produce the "best possible outcomes for customers."[152] We also

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[147] Nov. 21 Tr., Mr. Kruse at 114-115.

[148] Feb. 12 Tr., at 68.

[149] Feb. 12 Tr., at 68.

[150] Feb. 12 Tr., at 68.

[151] Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

[152] Feb. 12 Tr., at 72.

agree with Mr. Harris that the RTOs should pursue operational excellence to make certain that they're doing everything as best they can which would include the dispatch and fine-tuning.[153] We acknowledge that SCED improvement is a continual process. We also agree with Mr. Meyer that we should continually examine whether market rules are "in some way affecting economic dispatch that we ought to try to learn more about."[154] Finally, we believe that implementation of each of these recommendations should be contingent on a showing of cost effectiveness.

A. SCED Framework

- The Joint Board is not proposing any recommendations on the SCED framework issues of SCED definition, SCED history, or the debate over efficient versus economic dispatch at this time.

The Joint Board accepts the definition of SCED as it appears in Section 1234 of EPAct and as proposed for our use by FERC in its September 30 Order--"the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." SCED is merely a very complicated constrained optimization problem that involves a touch of art along with the science.

We do note that the EPAct definition of SCED is designed in such a way as it takes as a premise that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served. Such a definition might imply that, if energy is not being produced at the "lowest cost" or that consumers are not being "reliably" served, then SCED is not taking place. Yet, the evidence in this case shows that historically, system operators have always used some form of SCED. On the other hand, we intuitively know that, historically, energy has not always been produced in all regions of the country "at the lowest cost" and consumers in all places have not always been "reliably" served. Consequently, our examination cannot be on whether SCED exists in PJM and MISO. We know it does exist in PJM and MISO, as well as everywhere else, because material presented to the Joint Board shows that there is no other way to operate an electrical system. Accordingly, rather than considering only the existence or non-existence of SCED, our efforts were focused on assessing the extent to which the way PJM and MISO operate SCED (RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED) satisfies the least cost and reliability expectations implied by the definition of SCED.

The Joint Board accepts that SCED, in one form or another, has a long history. We agree with MISO that, "SCED has always been the necessary tool for ensuring reliable operations in modern systems."[155] No viable alternative to SCED, as a general system operating method, was offered in the record of this case and we are aware of no other viable alternative method for operating a modern electrical system. Alternative forms of conducting SCED were reviewed in Section IV above (in particular, alternative methods of pursuing the "least-cost" and "reliability" objectives of SCED), but SCED itself is unchallengeable.

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[153] Nov. 21 Tr., Mr. Harris at 99.

[154] Nov. 21 Tr., Mr. Meyer at 34.

[155] MISO Comments at 9.

The Joint Board believes that one of the principle focuses of the DOE Report—access by non-utility generators to the operator's SCED—is not a significant issue in the MISO or PJM areas. There was some discussion about improving opportunities for non-traditional resources such as wind power to participate through encouraging the use of new technology and methods to analyze and incorporate the benefits of diversity of generation into the dispatch. However, we did not hear any significant complaints from non-utility generators about access to PJM and MISO SCED.

The Joint Board extensively discussed the efficient vs. economic dispatch issue and that discussion is reviewed in Section V above. The Joint Board believes that MISO's statement that the debate over efficient dispatch is "a false debate, a red herring based on some unknown confusion" may be a bit hyperbolic.[156] However, the Joint Board agrees that, if done properly, economic dispatch will take into account all of the relevant economic, security, and operational factors. Efficient dispatch, on the other hand, would take into account a more limited number of factors. Accordingly, it is our position that the debate over economic vs. efficient dispatch is resolved, at least for the time being, in favor of economic dispatch.

The Joint Board recognizes PJM and MISO for using a common vendor for their dispatch systems. We accept the RTOs' representation that the basic mathematical formulation of the SCED function is the same for both RTOs. The fact that the common vendor delivered systems to PJM and MISO developed on a common platform potentially reduces disjoints at the PJM/MISO seam. Sometimes differences in outcomes result from differences in software. In the case of the PJM/MISO region, that is less likely to be the case.

B. SCED Benefits

1. Quantifying the Costs and Benefits of SCED

- An ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining market participant and state regulator confidence in the RTOs. The RTOs should establish a clear benchmark to assess the degree to which the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition, are being captured.

The first question in a SCED cost/benefit analysis might be costs and benefits compared to what? We know that SCED has a long history and that system operators have always used some form of SCED. Therefore, it would be meaningless to compare RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED with no SCED. It may be more appropriate to compare RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED with utility-by-utility cost based SCED. However, the RTOs took a number of incremental steps toward RTO-managed, bid-based, LMP, single clearing price, Joint Operating Agreement redispatch SCED. For example, MISO operated as a transmission functional control-only RTO for several years before initiating market operations.

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[156] MISO Comments at 7.

Which step should be considered the starting point for cost/benefit analysis? The multitude of cost/benefit studies discussed in the Joint Board process are not consistent on this framework.

Another issue involves the granularity of the benefits. Is it enough to show aggregate net benefits without accounting for net winners and net losers? The multitude of cost/benefit studies discussed in the Joint Board process are not consistent on granularity.

Many state regulators noted the importance of credible studies that seek relevant information and use accurate data to assess the benefits and costs of SCED as conducted by PJM and MISO.[157] As of February 12, 2006, some state regulators expressed their concern that the cost/benefit analyses that were provided were not sufficient to definitively resolve the cost/benefit issue.[158]

We understand that some cost/benefit studies are still being conducted, particularly by MISO. We believe that an ongoing demonstration of benefits from PJM and MISO managed SCED is important for sustaining stakeholder confidence in the RTOs.

We recommend that the benchmark against which the benefits of RTO-managed SCED are measured be carefully considered and explicitly specified. We are also interested in analyses that illustrate the degree to which PJM and MISO have captured the reliability and least cost objectives of optimal SCED, as described in EPAct's SCED definition.

2. Effect of the RTO Spot Markets on Forward Bilateral Contracting

- Appropriate efforts should be made to acquire necessary data to assess the impact of the SCED conducted by PJM and MISO on market participant forward bilateral contracting.

The importance of forward bilateral contracts as a method to reduce price risk for both suppliers and consumers has been well-documented in academic circles.[159]

Evidence presented to the Joint Board about the effect of the RTOs' spot energy markets on forward bilateral contracting appears to be in conflict, with one witness suggesting shrinkage in forward bilateral contracting and another suggesting that spot markets facilitate forward bilateral contracting.

Because of the importance of forward contracting and the apparent inconsistency of the two statements of the Joint Board witnesses, the Joint Board asked PJM and MISO a data request about the impact of their day-ahead and real-time energy markets on the willingness of market participants to bilaterally forward contract. In response, PJM stated in part that, "PJM does not have access to data that would allow PJM to accurately measure the amount of energy settled in

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[157] Questions from Chairman Davis, Commissioner Chappelle, Chairman Hardy and Commissioner Wefald answered by Mr. Harris and Mr. Torgerson on the studies used by PJM and MISO. See Nov. 21 Tr., at 76-85.

[158] Feb. 12 Tr., at 38.

[159] See, e.g., "Uniform-Price Auctions in Electricity Markets," Drs. Cramton and Stoft. This paper was provided to the Joint Board by PJM in response to Question #3 of the Joint Board March 8, 2006 data request. See, e.g., page 6 and 11 for a discussion of the importance of forward contracting.

our real-time market that has a forward hedging contract covering exposure to real-time prices."

Whether the SCED spot energy markets operated by PJM and MISO facilitate or hinder forward bilateral contracting is an important consideration in judging the value of such SCED spot markets. Accordingly, we believe efforts should be made to collect data relevant to this question.

3. Reliability

- While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue such standardization if its benefits exceed the costs for customers.

MISO stated that, "Without SCED, the lights would go out, under any system. However, reliability can be enhanced if the dispatch is (1) regional, (2) open to all generators, and (3) efficiently priced so that spot prices are consistent with SCED."[160]

One commenter stated that "Reliability is driven by the ability of the transmission system operator to understand the limitations of the transmission network and model these limitations in the transmission security analysis process."[161] Another commenter urged eliminating the multiple sets of reliability rules for the RTOs and stated that adopting common reliability rules will allow more efficient operations.[162]

In principle, we agree with both of these commenters. The better the RTOs are able to understand the transmission system they are operating and the better they model transmission system limitations in their analytical processes, the more likely it is that they will be able to operate the system nearer to its physical optimum without risking reliability. The greater the need on the part of the RTO to understand and reflect in operations modeling different reliability rules promulgated by different reliability authorities for different parts of the RTO geography, the more difficult the RTOs' job becomes and the less likely they will be to obtain optimal operation of the system (while still providing reliable operations).

We note that FERC has adopted a set of Electric Reliability Organization (ERO) rules and that an ERO application was submitted to FERC on April 4, 2006.[163] That application addresses the proposed relationship between the regional reliability organizations and the ERO. We hope that due consideration will be given to the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region.

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[160] MISO Comments at 11.

[161] AEP Comments at 10.

[162] Nov. 21 Tr., Mr. Naumann at 132.

[163] See FERC Dkt. No. RR06-1-000.

C. SCED Scope

1. Common Market/Cross-Border Trading

- The RTOs' common market development effort should include proposals for improving SCED over the seam between PJM and MISO. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly and in a cost-effective manner.

- With the Joint Operating Agreement, PJM and MISO developed a method for addressing transmission constraints in one RTO through redispatch by the other RTO when doing so is cost effective. MISO has suggested a way to improve this limited coordinated dispatch by exchanging preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. The RTOs are encouraged to further explore this idea of additional SCED coordination, taking cost-effectiveness into account.

The Joint Board agrees with Chairman Schriber that different operational rules and business practices between PJM and MISO have stifled transactions with neighboring utilities across these RTO borders.[164] We recognize that, in the common market docket, the RTOs are pursuing efforts to increase consistency between each other's approach on several operations and market elements. However, we agree with Chairman Schriber that this effort is not sufficiently comprehensive. As the RTOs consider any and all improvements in market and operations design and modifications to business practices, they should pursue such improvements with an eye to the effect of the change on the other RTO, and, ideally, develop all improvements jointly.

The Joint Board also notes that, in its response to the Joint Board's data request 6, MISO stated,

> Further coordination between the PJM and MISO dispatches is at least theoretically possible, and this further coordination could, in theory, produce a result that would, in effect, be equivalent to a combined, single dispatch for the combined systems. In other words, PJM would continue to dispatch the PJM system, and MISO would continue to dispatch the MISO system. However, when arranging their respective dispatches, the two RTOs would exchange preliminary dispatch results and associated prices, as well as information on constraints affecting the dispatch and prices. With this information being shared, each RTO would then run its dispatch and pricing models again, and achieve a revised dispatch and pricing result, which would in turn be shared with the other RTO. This approach is a possible alternative to more formal consolidation of the two dispatches, and does not present the kinds of dispatch expansion problems described above if either PJM or MISO (or some combined entity) were asked to dispatch the combined system.

The Joint Board would like to see this idea of additional dispatch coordination further explored.

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[164] Chairman Schriber Letter at 2.

2. Geographic Scope of SCED

- The RTOs are encouraged to continue timely analyses of the cost and technical feasibility issues involved with expanding the geographic scope of SCED. The continued analyses should encompass the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. In addition, each RTO should analyze the cost and technical feasibility of expanding its geographic area to include areas not currently under RTO managed SCED, as requested by utilities that seek voluntary membership in the RTO. However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and subject to relevant state law.

The Joint Board agrees with DOE that "the magnitude of the reliability and economic benefits realized from economic dispatch depends upon the size of the area that the integrated dispatch covers."[165] The Joint Board agrees with the DOE that a larger economic dispatch area "allows the dispatcher to take advantage of the load diversity across the area, to better allocate resources to load needs."[166] We note DOE's statement that, as an operational matter, "the larger RTOs report that the bigger the area that SCED covers, the more likely that operational limits can be respected with a solution that melds economics and reliability quickly and easily."[167] In addition, the larger the dispatch area is, the fewer are the seams between dispatch areas.

We acknowledge that PJM and MISO each currently cover a very broad geographic footprint. However, the question naturally arises of whether there are there further efficiencies that can be gained through the separate expansion of each of the RTOs or through the consolidation (in whole or in part) of their existing dispatch areas.

There are two practical factors that arise in considering this concept of SCED geographic scope. The first is the issue of cost. The second is the issue of technical feasibility. The Joint Board notes the RTOs' reference to the preliminary cost analysis that the RTOs conducted in Dkt No. ER04-375 on the question of forming a single dispatch across the combined PJM/MISO region. The Joint Board also notes the RTOs' commitment to studying that cost/benefit issue further and providing additional analysis in Dkt. No. ER04-375.

The Joint Board directly addressed the issue of technical feasibility through a data request question to the RTOs. Both RTOs responded that their existing systems could handle a 1,000 MW increase with no upgrades. Both RTOs responded that an increase of 50,000 MW of load and generation would require upgrades in computing capability and data storage capability. Both RTOs declined to speculate on the technological feasibility of managing increases in the magnitude of 100,000 to 150,000 MW without a more thorough technical evaluation.

Consequently, the question of the most cost effective geographic scope of SCED that is technically feasible is relevant, but has not yet been fully answered. The Joint Board encourages continued timely analysis of the cost and technical feasibility issues involved with expanding the

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[165] DOE Report at 27.

[166] DOE Report at 28.

[167] DOE Report at 28.

geographic scope of SCED. The continued analysis should encompass the possibility of each RTO expanding by adding geographic area that is not currently under RTO-managed SCED as well as the possibility of consolidating (either in whole or in part) PJM and MISO's separate SCED areas. The benefits would include increased load and generator diversity and we note Mr. Kruse's presentation that the set of resources available for dispatch in MISO has overall less diversity than does the resource set available for PJM dispatch.[168] However, as always, actions to expand the geographic scope of PJM or MISO SCED should be cost effective and would be subject to relevant state law.

D. Transmission Infrastructure

The Joint Board agrees with the DOE statement that SCED operation must take into account the "configuration of the existing transmission system."[169] We also agree with commenters like AEP who stated, "The key to optimizing the economic dispatch and maintaining reliability is a robust transmission network."[170] We also agree with Commissioner Nickolai's wry commentary that, although security constrained economic dispatch may be an efficient method of allocating scarce transmission resources, "if all we had was scarcity what we're going to see is prices that can just go up and up and up."[171] We agree with commenters who asserted that in order to get transmission built, long-term regional transmission planning, timely investment, and appropriate cost allocation are needed.

1. The Transmission Planning Process and Transmission Expansion Obligations

- Because adequate transmission infrastructure is important for the achievement of SCED's least-cost and reliability objectives, the RTOs should devote adequate resources and substantial management attention to the transmission expansion planning process.

- The RTOs are encouraged to bring to the attention of state regulators any situations in which transmission facilities found to be needed in the RTO expansion plan, are, nevertheless, not getting implemented in a timely manner.

- Provided that the RTO uses proper measures and a proper approach for inclusion of an economic transmission project (intended to address congestion issues) in its transmission expansion plan, the obligation on a transmission owner to exercise best efforts to implement such a project should be no different than its obligation to use best efforts to implement a baseline reliability project.

PJM and MISO each have a transmission expansion planning process. However, numerous parties are not satisfied with those processes. MISO even went so far as to admit that it needs to

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[168] Nov. 21 Tr., Mr. Kruse at 115-116.

[169] DOE Report at 46.

[170] AEP Comments at 6.

[171] Feb. 12 Tr., at 69.

improve its long-term transmission planning and procedures.[172]

Transmission planning and expansion are keys to pulling our respective geographic areas together—improving the operation of RTO-managed SCED, and facilitating a robust competitive electricity market. We recognize that, although the RTOs have already produced several transmission expansion plans, the concept of regional planning (especially in the MISO area which did not form around an existing power pool) is still relatively new. While local area planning cannot be abandoned, the benefits of effective wide-area, RTO-managed, transmission planning are significant. RTO-managed planning must be regional, independent, transparent, and participatory. It must also be continually improving.

We recognize that PJM and MISO strive to improve their planning processes with each subsequent transmission expansion plan that they produce. We also recognize that MISO recently made some formal changes to the transmission planning part of its tariff as a result of its regional expansion criteria and benefits ("RECB") task force effort and that PJM is considering improvements to its planning process through its regional planning process working group ("RPPWG"). The Joint Board commends the RTOs for undertaking those efforts and urges them to continue to devote adequate resources and substantial management attention to the transmission expansion planning process.

Similarly, the planning horizon must extend far enough into the future to provide market participants as much information as possible about future scenarios and risks. The RTOs have the needed geographic scope and range of information and analytical tools to be particularly well-suited to do this. We understand both RTOs to be currently examining such issues.

We generally understand that, once a transmission project meets the relevant RTO criteria and is placed into the RTO's expansion plan, the relevant transmission owning utility generally has an obligation to exert best efforts to see the project through siting and construction to operation. However, "best efforts" is a squishy concept, particularly in the case of a utility that might not find the RTO's identified transmission expansion solution to be in the particular utility's (or holding company's) best economic interest. We would hope that the RTOs would bring such circumstances, if they ever occur, to the attention of relevant state regulators, or to the Organization of PJM States, Inc. ("OPSI") and Organization of MISO States ("OMS") regional state committees, in a timely manner.

We also understand that there is some question about whether transmission owning utility obligations to undertake so-called economic transmission expansion projects (those aimed at cost effectively relieving transmission congestion) that the RTO finds necessary and includes in its transmission expansion plan are as strong as the obligations that apply to so-called baseline reliability projects. Commissioner Nickolai stated that, "we need to write a piece here that needs to make clear that it's going to take something enforceable in order to make sure that utilities are bringing additional resources to the table to keep those markets viable as the demand increases."[173] With respect to transmission, we agree. Provided that the RTO uses proper measures and a proper

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[172] Nov. 21 Tr., Mr. Torgerson at 98.

[173] Feb 12 Tr., Commissioner Nickolai at 70.

approach to inclusion of a project in its transmission expansion plan, the obligation to undertake an economic project should be no different than the obligation to undertake a reliability project.

2. Transmission Cost Allocation

- The RTOs are encouraged to continually improve their analytical modeling and forecasting capability to better assess beneficiaries of transmission expansion so as to improve transmission cost allocation.

Both RTOs have transmission cost allocation policies in their tariffs. Both RTOs are working on improving their cost allocation policies. Yet there is still dissatisfaction about the state of affairs with respect to transmission cost allocation.

The Joint Board recognizes that transmission cost allocation is a contentious and difficult subject. Nevertheless, improper cost allocation constitutes a barrier to the development of cost-effective transmission expansion and perpetuates less-than-optimal SCED. This is particularly the case with respect to so-called economic transmission expansion. Much of the controversy in transmission cost allocation derives from the imperfect ability to accurately model future unknowns. While complex, current beneficiaries of transmission expansion can often be identified. However, transmission lines have long lives and beneficiaries can and probably will change over time and in unforeseeable ways. The Joint Board acknowledges these difficulties, but encourages the RTOs to continually improve their analytical modeling and forecasting capabilities so as to reduce the range of foreseeable uncertainty scenarios.

3. Joint PJM/MISO Transmission Planning

- The RTOs are encouraged to devote adequate resources and substantial management attention to joint transmission planning and expansion processes so as to pull our respective geographic areas together, improve the operation of RTO-managed SCED, and facilitate a robust competitive electricity market.

Some parties commented that PJM and MISO's long-term planning needs to be coordinated and done jointly to ensure an adequate transmission grid to optimize the ability of SCED in LMP markets.[174] We understand that PJM and MISO have a joint planning process in place under the JOA and that the RTOs are proceeding with initial efforts to conduct a joint plan.

Given the interwoven nature of the boundary between PJM and MISO, joint transmission planning is critical. For example, it was also suggested that joint and common planning is needed to help address the loop flows that the dispatch of one system creates on the other.[175]

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[174] Joint State Commission Comments at 10, WPSRC Comments at 2 and 6, Chairman Schriber Letter at 3, Nov. 21 Tr., Mr. Torgerson at 98-99, Mr. Tatum at 144 and Mr. Welch at 152.

[175] AEP Comments at 9 and Chairman Schriber Letter at 2-3 (loop flows can produce congestion on the neighboring system, requiring more uneconomic (out of merit order) dispatch to overcome the loop flow effects, e.g., the Lake Erie loop flow.).

The most effective transmission expansion project to address a reliability or economic issue in one RTO may be in the other RTO. Similarly, cross-boundary solutions to problems should get no less consideration in the planning process than within-RTO solutions.

We understand that inter-RTO transmission planning and expansion are new concepts. Nevertheless, their importance is significant. We hope and trust that the RTOs' joint planning and expansion processes will receive the needed attention and resources that they deserve so as to pull our respective geographic areas together, to improve the operation of RTO-managed SCED, and to facilitate a robust competitive electricity market.

E. RTO Independence

- RTO independence is critical for the RTOs' ongoing credibility. Accordingly, PJM and MISO are encouraged to continue to strive for independence as a bedrock principle. Both state and federal regulators have a role in the oversight of RTO independence.

At the February 12 meeting, Commissioner Nickolai suggested that the Joint Board "review the governance of the RTOs to help assure that they truly are independent, to the extent that we can make them independent operators of the markets and the grid."[176] He raised a question about "the extent to which they are [in]dependent actors versus the extent to which they feel that they must be agents of their members and transmission owners."[177] He stated that the assurance of independence is an important foundation for "confidence that the grid and the markets are going to be operated in a manner fully consistent with the goal of maximizing the economic benefit to the public."[178]

We agree with Commissioner Nickolai that RTO independence is a critical foundation for supporting stakeholder confidence in the RTOs' markets and operations, including SCED. To assure their long-term effectiveness and credibility, the RTOs must be careful not become an advocate for any one position or sector. They instead need to be neutral operators of the market and an impartial information resource to all.

Transmission revenues, which are determined at least partly by the RTOs' SCED operations, are paid by customers in the RTO region. MISO's fiduciary obligation to maximize transmission revenues, for example, may, at least partly, affect MISO's SCED operations and customer costs. PJM may have similar issues. We stress that no evidence was presented in the Joint Board process to call PJM's or MISO's independence into question. However, we believe that ongoing oversight of RTO independence is prudent.

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[176] Feb. 12 Tr., at 68.

[177] Feb. 12 Tr., at 68.

[178] Feb. 12 Tr., at 68.

F. Market-Based SCED

1. Market Monitoring

- Some state regulators do not believe that they currently have sufficient access to the data needed to evaluate and oversee the RTOs' operation of market-based SCED. The RTOs' policies for limited state regulator access to data should be revisited.

The Joint Board examined the single clearing price SCED auction vs. the pay-as-bid approach. In particular, we found value in the Cramton/Stoft paper that PJM provided. This issue should not be forgotten because the soundness of the single clearing price approach depends directly on the competitive behavior of the marginal bidder. Market conditions and market participant behavior in a market-based SCED require constant regulatory oversight. However, for the purposes of this report, and subject to the discussion below, the Joint Board is satisfied with the RTOs' response to our data request concerning the single clearing price SCED auction vs. the pay-as-bid approach.

The Joint Board extensively considered the bid-based vs. cost-based approach to SCED.[179] Each of these methods has merits and shortcomings. As the RTOs explained in their response to the Joint Board's data request, the cost-based approach requires extensive administrative oversight and constantly risks being out-of-date. On the other hand, the bid-based approach leads naturally to offers at marginal cost (the most efficient outcome) provided that sufficient competitive pressures exist in the market. Accordingly, under bid-based SCED, vigilance must be maintained by the RTOs' Market Monitoring Units, state regulators, and federal regulators on monitoring the level of competitive pressure in the market.

Similarly, the reasonableness of using the single clearing price auction approach, rather than a pay-as-bid approach, to clearing the real-time market and operating SCED depends directly on the assumption that the marginal unit in any particular dispatch interval is acting competitively and bidding at its marginal cost.

If the competitive market assumption or the competitive behavior assumption is false, and market power mitigation is not imposed, then SCED, as managed by PJM and MISO, may not produce optimal (e.g., least-cost) results within or outside a zone of reasonableness.

PJM's response to the Joint Board's March 8 data request Question 2 stated that "It is reasonable to seek to assess the competitiveness of wholesale power markets in PJM." PJM goes on to state, "That is the primary focus of the PJM Market Monitoring Unit (MMU)." PJM is off-the-mark, however, if it is suggesting that we should be satisfied that the PJM MMU (and its counter-part for MISO) is focused on the competitiveness of wholesale power markets, and that there is no need for Joint Board member agencies to be concerned about this critical issue. Given our charge to ensure the "best possible outcomes for consumers," the acceptability of continuing RTO-managed bid-based SCED

[179] We note that both PJM and MISO initially used cost based approaches before evolving to a bid-based approach.

depends directly on the competitiveness of the market and the exercise of competitive behavior by the marginal resources. State regulators have a vital role in market monitoring and must have the ability to conduct critical analyses and oversight of RTO markets along with the RTOs or the RTOs' market monitoring units.

Accordingly, state regulators must have access to the data and information necessary for us to confirm the competitiveness of the RTOs' market outcomes and the competitiveness of market behavior. There is no other way for us to achieve the level of confidence that is needed for sustained support of RTO-managed bid-based dispatch. Some state regulators believe that the RTOs have not been sufficiently forthcoming with the data needed by state regulators and the RTOs' policies for limited state regulator access to data need to be revisited.

Monitoring data regarding market behavior and market outcomes in a timely manner is important for identifying potentially anticompetitive market behavior, which could adversely affect the affordability and reliability of service from the RTOs' SCED operations. Monitoring such data in a timely manner is also important for other policy and technical decisions, such as states' decisions regarding expansion of generation, demand-response, and transmission resources, that also influence the affordability and reliability of service from the RTOs' SCED operations.

2. Marginal vs. Average Losses in the Dispatch

- When determining their respective dispatches, MISO uses marginal losses and PJM uses average losses. The material presented to the Joint Board shows that, while there may be implementation issues to resolve, using marginal losses improves dispatch efficiency. Accordingly, the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

The Joint Board notes that MISO uses marginal losses in its dispatch but PJM uses average losses. The Joint Board notes that on May 1, 2006, FERC issued an Order in Dkt. No. EL06-55 requiring PJM to implement a locational marginal loss method for allocating transmission line losses by September 2006. According to PJM, it may not be able to implement marginal losses in this time frame, and may request an extension within which to comply with the Order.

Given that at least temporarily PJM and MISO will be operating on different dispatch methodologies, the Joint Board explored the marginal and average losses dispatch topic through a data request. Both RTOs agree that, "The marginal loss approach is more efficient because it tends to minimize system losses as part of the dispatch algorithm which in turn minimizes to overall cost to serve load." Both RTOs also agreed that, "while marginal loss implementation does increase market efficiency, certain practical implementation issues do exist with the marginal loss approach." The RTOs state that, "These issues are not insurmountable but their resolution has created implementation complexities in RTOs where marginal losses have been implemented." Finally the RTOs state that,

> The PJM/MISO market to market coordination process has worked well in

providing coordinated transmission congestion management between the PJM and MISO markets. Therefore, PJM does not believe the difference in the loss models between the RTOs has adversely impacted interregional transmission congestion coordination. However the difference in the transmission loss pricing may have a small impact on price convergence between the markets. Since marginal loss pricing is a relatively small impact compared to congestion pricing, the impact is limited.

The Joint Board recognizes that the efficiency gains available from uniform use of marginal losses across PJM and MISO may be small compared to the efficiency gains achieved through the adoption of LMP congestion pricing. However, that is not the point. Consistent with our charge to ensure that the "best possible outcomes for customers" are achieved, we believe that the issues associated with losses as they apply to PJM and MISO SCED should be analyzed and appropriately resolved.

3. Ancillary Services/Multiple MISO Control Areas

- The operation of SCED must take transmission ancillary services into account. PJM and MISO have distinctly different methods of treating ancillary services. There are potentially significant efficiencies to be gained through improved co-optimization of ancillary services and energy in the dispatch and PJM and MISO are encouraged to continue to strive to improve on efficiencies gained in the area of ancillary services.

SCED must take into account ancillary services such as downward-and-upward regulating margin requirements of the system and operating reserves.

PJM and MISO have distinctly different methods of treating ancillary services. PJM operates markets for both regulation and operating reserves and co-optimizes these ancillary services with energy to improve the assignment of the more cost-effective resources throughout the market.

MISO currently does not centrally dispatch the Regulation or Spinning Reserve services. Rather, each individual Balancing Authority is responsible for assigning the required amount of Regulation and Spinning Reserve within its area, and directing the deployment of those services based on its individual ACE. The individual Regulation and Spinning Reserve assignments made by the individual Balancing Authorities are communicated back to the MISO control center for inclusion in the UDS economic dispatch solutions. The Joint Board notes that on April 3, 2006, in Dkt. No. ER04-691-000, MISO submitted an informational filing to FERC regarding the centralization of some control area functions. The Joint Board also notes that consideration of ancillary services market issues is underway in the MISO stakeholder process.

G. Demand-Side Response

- The PJM and MISO markets must develop more ways for demand response to participate in the dispatch. Improvement in demand response opportunities is not just an RTO responsibility. The Joint Board encourages PJM and MISO to work with state regulators and policy-makers to improve SCED by improving cost effective demand responsiveness

to price.

Most of the electricity demand enters into the SCED algorithm as non-price responsive must-serve "load." It is treated as load that must be served and energy that must be provided regardless of price, taking into account the practical limits of the system.[180] Such large levels of non-price responsive demand provide conditions precedent for volatile spot prices.

Cramton and Stoft describe a normal two-sided, single clearing price auction as follows:

> Buyers with bids at or above the clearing price pay the clearing price for the quantity purchased. Suppliers with offers at or below the clearing price are paid the clearing price for the quantity sold.[181]

This market design works best with adequate levels of price responsive demand.

There was general consensus among participants in the Joint Board and commenters that the PJM and MISO markets must develop more ways for demand response to participate in the dispatch.[182] Demand response capability increases the efficiency of SCED by increasing dispatch flexibility and resource diversity. Increasing demand response is not just the RTOs' responsibility. It will require the full participation of state policy makers and industry participants as well. However, the RTOs are in a unique position to assist due to their role in centralized transmission control and regional market operation. Therefore, we urge the RTOs to work with state regulators and policy-makers to improve SCED by improving demand responsiveness to price.

VI. CONCLUSION

In crafting the recommendations above, we were guided by our Joint Board Chairman, Commissioner Brownell, to strive for ways to ensure that SCED will enhance the reliability and affordability of service and produce the "best possible outcomes for customers."[183] We believe our recommendations reflect that focus and respond directly to Congress's invitation for us to develop recommendations on SCED that will enhance "the reliability and affordability of service to customers in the region."[184] If improved benefits of the PJM and MISO organized markets are going to be realized, the RTOs and regulators must remain vigilant in exploring and implementing cost-effective improvements in the RTOs' SCED operations.

We acknowledge that implementation of some or all of these recommendations cannot proceed without the development of stakeholder consensus. We further realize that time may be needed

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[180] Hence, the importance of accurate load forecasting as noted in the DOE Report at 51.

[181] "Uniform-Price Auctions in Electricity Markets" at 2.

[182] Nov. 21 Tr., Mr. Torgerson at 98, Mr. Harris at 54 (PJM has seen benefits of demand response) and 104, and Mr. Kruk at 149.

[183] Feb. 12 Tr., at 72.

[184] Pub. L. No. 109-58, § 1298, 119 Stat. 594, ___ (2005).

to conduct more detailed studies (including cost/benefit analyses) and to build the needed consensus. Finally, we believe that implementation of each of these recommendations should be contingent on a showing of cost effectiveness. Nevertheless, we believe that these recommendations form an agenda for RTO management to pursue. Just as market improvements are not implemented without careful planning and broad support, we expect that none of these recommendations will be dropped without the same kind of planning and public consideration.

At the February 12 Joint Board meeting, Commissioner Brownell referred to the Joint Board process as the "beginning of a model that I hope will be continued to resolve issues that are thorny and difficult, but because of the shared nature of our jurisdiction, I think it will be increasingly important to use forums like this to address issues that are regional, but obviously have state implications."[185] We hope so too. We look forward to seeing the current SCED Joint Board process through to fruition and also look forward to working together with our FERC colleagues on further joint board endeavors.

[185] Feb. 12 Tr., at 3.

Attachment A

Dissenting and Concurring Comments of the Indiana Utility Regulatory Commission to the Joint Board Report

SECURITY CONSTRAINED ECONOMIC DISPATCH

The Indiana Utility Regulatory Commission ("IURC") concurs with the Joint Board's discussion and conclusion on the *process* of Security Constrained Economic Dispatch ("SCED") that was the charge to the FERC – State Joint Board from Congress pursuant to the Energy Policy Act of 2005 (EPAct05).[186] Nonetheless, the Report's excursions from this specific charge create unintended and unfortunate misapprehensions in the readers mind.

A. THE REPORT EXCEEDS THE SCOPE REQUESTED BY CONGRESS AND THEREBY DEPRIVES PARTIES OF DUE PROCESS

The IURC believes that this Report by the Joint-Board exceeds the scope envisioned by Congress. The IURC is, therefore, concerned that stakeholders and state commissions that provided information to the Joint Board responsive to the narrow scope were unfairly deprived of providing information on the more expansive scope contained in the Joint Board Report.[187] As a

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[186] Specifically, the FERC Order establishing the Joint Board said that each Joint Board is authorized to:
(1) "consider issues relevant to what constitutes 'security constrained dispatch'";
(2) "consider how such a mode of operating an electric system affects or enhances the reliability and affordability of service to customers in the region concerned"; and
(3) "make recommendations to the Commission regarding such issues."

The DOE was tasked with working with States to:
(1) study the procedures currently used by electric utilities to perform economic dispatch;
(2) identify possible revisions to those procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch; and
(3) analyze the potential benefits to state and national residential, commercial, and industrial electricity consumers of revising economic dispatch procedures to improve the ability of non-utility generation resources to offer their output for inclusion in economic dispatch.

[187] By way of additional examples of Recommendations that were extra topical contained in the Joint Board Report, some states believed that the FERC Orders limiting state commission access to confidential information from the PJM, the Midwest ISO, and the Midwest ISO's Independent Market Monitor should be revisited. Some states wanted to stress the importance of the independence of the governing structures of the RTOs. The IURC is not aware that any party questioned the importance of independent governance. Rather, there was considerable comment by Independent Power Producers – the area of primary interest to the Department of Energy - that complimented the independence of the RTO governance from market participants in contrast to discriminatory terms and conditions offered by individual utilities in regions not served by RTOs. One of the Recommendations noted correctly that some matters are outside their control but still charged the RTOs to apparently consider actions beyond their authority.

> *While it is not necessarily under the RTOs' control, developing common reliability rules applicable across each RTO's region or, ideally, across the combined region, could promote more efficient SCED operations. The RTOs are encouraged to assess the benefits of standardization of reliability rules across each RTO's footprint and across the combined PJM/MISO region and pursue them if they exceed the costs.*

result, the "Recommendations" that were contained in the Report were not as well-informed as they could have been had the enlarged scope of the Joint Board discussions been appropriately noticed.

Specifically, the IURC understood the charge by Congress to address the *process* of security constrained economic dispatch. Some topics, such as the Recommendation for RTOs to offer additional demand response, while improving the *outcomes* of SCED, are extra topical because the fundamental processes of the dispatch would not change with additional demand-response. Moreover, despite the Recommendation in the Joint Board's Report that RTOs offer more demand-response programs, it is unclear what unilateral action RTOs would be encouraged to take since some states regard demand response to be state jurisdictional.

B. RECOMMENDATIONS WERE NOT SUBJECTED TO VOTES OF THE JOINT BOARD

Because stakeholders and state commissions could not have reasonably anticipated the more expansive scope of the Joint Board discussions, it would be difficult for the Congress to assess the weight that should be accorded to the Recommendations in the Report. Moreover, because no votes were taken on the Recommendations nor was there any discussion of prioritization of the Recommendations it is impossible for Congress to assess the appropriate weight of any of the Recommendations. The IURC is concerned that, by characterizing the comments in the Joint Board's report as "Recommendations," each of the Recommendations may be inappropriately thought to carry the imprimatur of each state.

C. THE INTEREST IN A MORE EXPANSIVE LIST OF ISSUES WARRANTS FURTHER STATE – FEDERAL DIALOGUE

For those topics that were discussed by one or more participants that were extra topical but included as Recommendations, the IURC would prefer that those topics be the subject of further FERC -State Joint Board discussions. The limited amount of time for discussions was not sufficient for a full airing of the SCED issues that were the charge of the Congress and certainly not enough to address all of the issues contained in the Joint Board Report. The IURC is, therefore, concerned that the Joint Board Report trivializes important issues such as the on-going need for RTOs to quantify costs and, where possible, the benefits of RTO facilitated markets. Further discussions would allow all state commissions and stakeholders to have a more complete discussion of these important issues.

The IURC understands the desire of some state commissions to use this Report to inform Congress on a variety of issues that were not specifically the charge to the Joint Board. The IURC, while concurring that providing Congress with important information is good public policy, believes such information would be improved by having further Joint Board discussions on matters that are critical to the Federal Energy Regulatory Commission, state commissions, and stakeholders.

D. THE RECOMMENDATIONS MAY LEAVE AN ERRONEOUS IMPRESSION THAT IMPORTANT ISSUES ARE NOT BEING ADDRESSED AND THEREBY MINIMIZING THE COMPLEXITY AND CONTROVERSIES

The IURC is concerned that some of the Recommendations may give Congress the impression that state commissions, stakeholders, the Midwest ISO and the PJM are not seriously addressing

critical issues. By way of examples, the Recommendations include pricing of economic and reliability transmission projects. The Report makes no mention that these matters have been and are being addressed by the Midwest ISO, the PJM, stakeholders, and state commissions. As importantly, the Joint Board's Report makes no mention that these topics have proven to be very controversial and complex.

The IURC does not believe it is sufficient to allege that the RTOs are not devoting enough resources to a specific issue. Rather, it is incumbent upon the Joint Board to offer substantive suggestions and, ideally, to explicitly acknowledge that state commissions have a commensurate obligation to dedicate resources. The lack of substantive suggestions contained in the Report is indicative of the complexity of the issues. The IURC does not believe that the public interest is well-served by the vague suggestions that more attention needs to be given to these topics.

E. THE REPORT DOES NOT ADEQUATELY EMPHASIZE THE NEED FOR COST-EFFECTIVENESS AND ACHIEVING NET BENEFITS

The IURC is concerned that Congress may be left with the impression that the Joint Board is not concerned that the enhancements contained in the Recommendations provide net benefits to wholesale markets and, ultimately, to consumers.

The IURC, because its utilities are in two Regional Transmission Organizations, has a deep interest in the efficient development of the PJM and Midwest ISO Joint and Common Market. The IURC, however, believes that the evolution to a Joint and Common Market should be cost-effective. As part of this evolutionary process, the IURC agrees with the Joint Board that both RTOs ought to consider the ramifications of adding different functions so that they are compatible with the functions of the other RTO but the IURC is satisfied that price convergence between PJM's and the Midwest ISO's facilitated markets are sufficient indicia that the markets are largely operating as if they were a single market. Therefore, until such time as the technical feasibility is achievable and the net benefits warrant a single dispatch (or other identical functions) the on-going evolution is appropriate.

CONCLUSION

The Joint Board's Report does an excellent job of addressing the issues that the Congress asked the Joint Board to address regarding SCED. However, despite the best intentions of the authors to provide a wide-sweep of information to the Congress, because the Report addresses matters outside of the scope of the EPAct05 without sufficient input by experts or vetting by members of the Joint Board, the Report risks minimizing the importance of a number of critical issues. The several topics and Recommendations that were beyond the scope of the charge to this Joint Board would, more appropriately, be topics for future FERC – State Board dialogue. The IURC is concerned that such issues as the on-going need for RTOs to quantify costs and benefits or for RTOs to demonstrate that additional RTO functions provide net benefits for the reliability and economic efficiency of the wholesale market and, ultimately, retail customers, were not adequately considered. The lack of full consideration of all the issues contained in the Report can not, therefore, be construed as foundations for the Recommendations or for reasoned conclusions.

Attachment B

Dissenting Comments of Montana Commissioner Greg Jergeson to the Joint Board Report, Docket No. AD05-13-000

Like motherhood and apple pie, no one can oppose Security Constrained Economic Dispatch (SCED) of electricity. That is particularly the case if one assumes that the economic dispatch of electricity will yield the lowest possible cost of electricity for the consumer, even considering the security constraint aspects of SCED.

Just as the recipe ultimately determines whether the apple pie is edible, the recipe will determine whether SCED is palatable. In my considered judgment, the recipe for SCED articulated and implied in the document submitted by the PJM/MISO Joint Board does not result in a palatable public policy outcome. Before members of Congress issue ringing press releases that the Joint Board document heralds a new day of reasonably priced electricity for the consumer, they should carefully review and consider the details in the document before they succumb to the inevitable hype.

When this joint board process began, I mistakenly assumed that the definition of SCED as presented in EPAct 2005 was meant to achieve economic benefits for the consumer, i.e. the lowest possible cost electricity. However, the further explanation of the definition contained in the April 28 Joint Board draft, disabused me of that notion. *"The definition of SCED is, such that it takes, as a premise, that SCED will result in the production of energy "at the lowest cost" and that consumers will be "reliably" served."* (emphasis added) I interpret that language to confine consumer benefits to reliability. The economic benefits will accrue to the commercial players in the industry.

That the regime outlined in the Joint Board document will yield 'reliability" benefits to the consumer is, at best, arguable. We're talking about grafting an enormously complex economic management system (SCED and RTOs) on an already complex physical system, the grid. Just look at the hundreds, perhaps thousands of pages in the tariffs that MISO and PJM have filed with, and that have been approved by FERC. Consider that the regime outlined in the Joint Board document will inevitably require hundreds and thousands more pages of tariffs. At some point, the rule that the more complex a system is, the more vulnerable it is to failure applies. From my former life as a farmer, it is not with a whole lot of fondness that I remember the occasions when the failure of a $3.98 bearing hidden behind $15,000 worth of iron, steel, rubber and plastic brought the entire $100,000 machine to a grinding halt.

My suspicions that the economic benefits of SCED are reserved for the commercial interests in the electricity sector, not the consumers, was most aroused by the Joint Board document discussions relating to "Single Clearing Price vs. Pay-as Bid Approach which occur in several places in the document. The document clearly comes down on the side of "Single Clearing Price" wherein all sellers will receive the highest clearing price that fills the load even if they have bid in at a lower price. The buyers (ultimately the consumers) will pay that higher price for

all load purchased. To find economic benefit for consumers, i.e. lower prices, in this scenario requires real Orwellian logic. The document discussion goes on to pooh-pooh Pay-As-Bid as too given to game playing in the bidding process by generators and, thus would require (gasp!) too much government regulation to work.

Though I have received numerous assurances that there is no intention to dismantle the vertically integrated, state regulated utilities in those states where that continues to be the model, I fear the virulence of the anti-regulation arguments contained in the Joint Board document will appear as a license for some to attempt the federal imposition of electricity deregulation on those states who have retained the traditional, regulatory model.

I appreciate and applaud the purpose of the market monitor to protect consumers against illegal, anti-competitive, and monopolistic manipulations of the market. However, I fear the task of the market monitor is akin to the challenge facing those charged with stamping out the use of performance enhancing drugs in athletics. Just as the screens are developed to detect the current generation of those drugs, enterprising souls develop a new generation of drugs that are not detected by the latest available screens. And so the cycle goes on.

I have not, in this dissent, attempted a line-by-line critique of the joint board document. That choice is based on my view that the entire paradigm indicated in the document is flawed, and that the document itself will continue to be a moving target up until the very minute it is submitted to the FERC.

Therefore, I respectfully dissent from the document submitted by the PJM/MISO joint board.

Greg Jergeson
Montana Public Service Commission
District 1

Attachment C

Concurring Comments of Joint Board Virginia Representative Howard M. Spinner to the Joint Board Report

Docket No. AD05-13-000

Introduction

By order of September 30, 2005, the Federal Energy Regulatory Commission ("FERC" or "Commission") opened this docket and formed joint federal state boards to, on a regional basis, study "security constrained economic dispatch." FERC Chairman Kelliher set an early May, 2006 date for the submittal of this Joint Board's report to the Commission. These comments specifically address the Bid-Based vs. Cost-Based SCED issue and the Total Revenue Recovered by Generators Through the RTOs' LMP-Based SCED Compared to Aggregate Generator Production Cost issue as set forth in the Board's report. These comments support the position that central issues raised in these two sections are left unanswered due to the complete yet understandable lack of any rigorous analysis undertaken by the Joint Board in this proceeding.

It is certainly understandable that, given the time frame allotted for this Joint Board's work, new, independent and meaningful *quantitative* analysis was not possible. Nevertheless, this lack of analysis necessarily prevents this Board from drawing any conclusions regarding the issues identified in the preceding paragraph. Furthermore, RTO assertions that their operations produce the best possible short-run and long-run outcomes for consumers are nothing more than assertions that have not been verified by independent analysis.

Background

In convening this Joint Board, the FERC acted pursuant to section 1298 of the EPACT of 2005. The MISO/PJM Joint Board is authorized to consider issues relevant to what constitutes "security constrained economic dispatch," how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned, and to make recommendations to the Commission regarding such issues.

For purposes of this proceeding, the FERC has adopted the definition of economic dispatch provided in section 1234(b) of the Energy Policy Act of 2005 as the definition of "security constrained economic dispatch," *i.e.*, "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

The position set forth in these comments is that, due to the absence of performance of any independent analysis or the submission of any data by any party or stakeholder, it is impossible for this Joint Board to answer perhaps the most important question placed before it by Congress. That question derives from the EPACT's charge to consider "how such a mode of operating an

electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned." This key question can be restated simply as "does the current operation of the electric system in the MISO/PJM 'footprint' produce required electrical output in a least-cost manner given the current stock (inventory) of generation and transmission assets?"

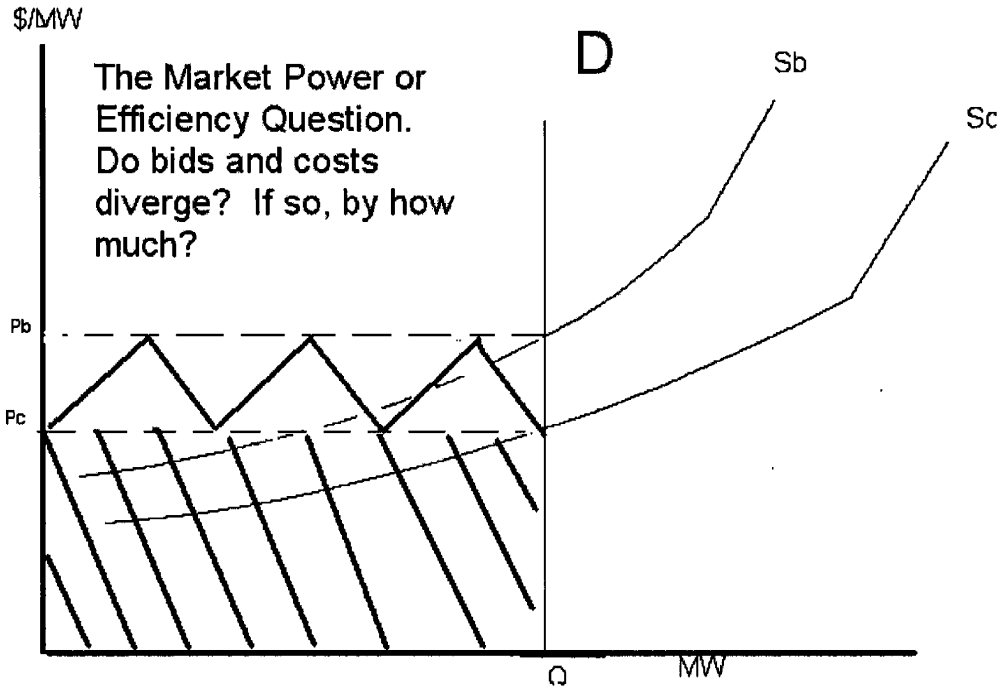
Most relevant to the Board's inquiry is the issue of the cost of electric service ultimately paid by consumers. One important factor that should influence this key metric is the actual resource cost expended to produce a given quantity of electrical output. A concern stated by at least some Joint Board members is that wholesale electric prices may inappropriately diverge from production resource costs. Some members worry that this divergence may ultimately drive up retail electricity prices.

Below these comments address the "bid vs. cost" and the "generator net revenue" issues in turn. The bid vs. cost issue is an efficiency issue. The generator net revenue issue is a fairness or equity issue. Efficiency and fairness issues are related in that if the dispatch is inefficient, that inefficient dispatch can exacerbate unfair market results. For example, if the exercise of market power changes the competitive bid-based dispatch from what would otherwise have been a least (resource cost) dispatch, the bid-based dispatch is inefficient. If this bid-based dispatch causes much higher market clearing prices, some might consider this result unfair as well.

The Issue of Bids vs. Costs. --- The Efficiency Question

During the Board's proceeding, most, but not all of those forwarding comments to the MISO/PJM Joint Board have assumed that MISO/PJM competitive electricity markets function well and that resulting wholesale electricity prices in these markets do not significantly vary from the actual resource cost of electricity production. In other words, generation unit specific offers to sell electricity in these wholesale markets reasonably approximate unit specific short-run marginal cost. As such, it is assumed that the exercise of market power does not adversely impact market outcomes. However, some Joint Board members and stakeholders are not yet ready to make such an assumption regarding the functioning of organized electricity markets absent a rigorous demonstration that the wholesale market operates in a reasonably competitive manner.

The issue boils down to a comparison of bid-based dispatch as currently practiced in competitive organized markets to the dispatch that would have prevailed under the prior regime of cost-based dispatch. Since it is very hard to know what the cost-based dispatch would have been absent industry restructuring, a reasonable starting point for rigorous analysis is a quantification of the cost of the current dispatch based on the best available cost data possessed by the RTOs. Thus, bid-based and cost-based dispatch could be compared. Consider the following diagram:



Here, under a single price auction regime where all generators offer to sell electric energy at marginal cost, customers would pay the lower cross-hatched area (Pc*Q) for energy during the period being examined. Although not explicitly shown on the graph, under cost-of-service regulation, customers would be responsible for paying for energy for this period as determined by the area under the supply curve Sc. Under bid-based competition as currently practiced in organized wholesale electricity markets, customers additionally pay the upper cross-hatched area; the total energy bill for the period under bid-based competition is given by Pb*Q.

The comparison of these alternative payment responsibilities for electric energy is a meaningful exercise. This is true even though, under both pre and post restructuring regimes governing the provision of electric service, other long-run and short-run costs need to be accounted for. The point is that before one forms an opinion regarding the appropriateness of market outcomes, one should have --- as a starting point --- a good handle on the relative sizes of the areas described above and shown in the graph. Unfortunately, up to this point in this proceeding, the RTOs have not provided the data necessary for independent entities to conduct such analysis.

Given any short-run supply curve for electric energy, we would expect the bid-based supply curve to be found up and to the left of the cost-based supply curve. For any given supply curve, movement up and to the left is bad for consumers; it means higher prices for any given level of demand. On the other hand, moving the supply curve out and to the right is good for consumers; it lowers prices, all else held constant. The exercise of market power moves the supply curve up and to the left (the bad direction) while the pressures of a truly competitive market move the supply curve out and to the right (the good direction). The simple question here --- the essence of the bid vs. cost issue --- is which force dominates? Market power or competitive pressure? Where does the supply curve lie relative to where it would have lain in the absence of restructuring. These comments support the proposition that this crucial question is,

unfortunately, left unanswered by this Joint Board.

In their paper[188] *Uniform Price Auctions in Electricity Markets*, Peter Cramton and Steven Stoft clearly state that "Marginal cost bidding has the further benefit of efficient dispatch. Energy is supplied by the least-cost units." The authors go on to explain that "Real markets are not perfectly competitive," and that the profit maximizing behavior of real generators in today's competitive, bid-based RTO administered markets leads to bidding strategies that necessarily deviate from those under perfect competition. The question that the authors do not answer is how those deviations affect market outcomes. The last paragraph of the paper speaks for itself:

> The theory of bidding in uniform-price auctions under conditions of imperfect competition has been developed extensively in the economic literature (Ausubel and Cramton 2002, Klemperer and Meyer 1989). In this theory, each supplier submits a bid function to maximize its profits given its marginal cost curve, its expectations about market demand, and its expectations of the supply curves of the other bidders. The theory has several important implications: (1) so long as there is some probability that the supplier's bid may affect the clearing price, the profit maximizing bid curve exceeds its marginal cost curve; (2) the spread between its optimal bid and marginal cost increases with the quantity that the bidder is supplying; (3) the spread between its optimal bid and marginal cost increases the less responsive the supply of the other bidders is to price; (4) the greater incentive for larger bidders to inflate bids above marginal cost implies a short-run inefficiency—too little of the market is served by the largest bidders; and (5) forward contracts have the effect of mitigating incentives to bid above marginal cost, and indeed, can create incentives to bid below marginal cost.

On January 27, 2006, FERC State Outreach circulated a "draft report" presenting a brief discussion of security constrained economic dispatch, how dispatch is done in the region, and a summary of the issues and recommendations made on the record up to that point in time. As noted in the body of this Joint Board report, the "draft report" listed three recommendations from the DOE November 7, 2005, report titled "*The Value of Economic Dispatch, A Report to Congress pursuant to Section 1234 of the EPACT of 2005.*" However, the draft report omitted the following recommendation:

> One industry observer proposes a study of areas that perform bid-based economic dispatch within real-time markets, to compare the market-clearing price outcomes and total costs against the true production costs of the actual units dispatched. This study would presumably examine two questions: how NUG bids in regulated utility dispatch (and utility-owned generator bids in centralized markets) compare to actual production costs, and how total electricity costs in centralized markets compare to total costs in the *(sic)* of the same production priced at its actual production cost. Such a study would require significant data or assumptions, incorporating energy costs and line losses within economic dispatch. It would

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[188] This paper was submitted on March 22, 2006, to this Joint Board in this matter by PJM in response to the Joint Board's March 8, 2006 data request. See page 16

> have to recognize that a significant amount of the total energy consumed within a region comes from utility-owned generation and bilateral contracts that are not priced at the MCP. In addition, the study would need to incorporate ratepayer charges for capacity for utility rate-based plants and stranded cost recovery, any payments made under a market-capacity-revenue scheme, and acknowledge any savings that might accrue to ratepayers for NUG capital costs left unrecovered from an energy-only revenue stream. (DOE Report to Congress Pursuant to Section 1234 of the EPACT of 2005, November 7, 2005; pages 51 and 52)

The above paragraph describes an approach to studying the "bid vs. cost" issue. Such a study was not conducted pursuant to this proceeding. As such, it seems reasonable that before this Board draws any conclusions regarding the "affordability of service to consumers in the region" as it relates to the functioning of security constrained economic dispatch in the PJM/MISO region, a study along the lines as set forth above should be undertaken.

As noted in the omitted recommendation, such a study would not be a simple affair. The formulation of required assumptions would potentially be controversial. In fact, when FERC staff participant and presumed draft report writer William Meroney was asked why the above recommendation was omitted from the January 27, 2006, draft report, Mr. Meroney replied:

> I think if we left that one out it was probably largely -- it seemed not so much outside of the scope in terms of being technically relevant, but just that doing that study itself seemed beyond the scope of what the Board could accomplish in the time allotted.[189]

At this point Commissioner Brownell added:

> And, Mr. Spinner, I think it gets back to the point I think that Chairman Hardy made and others made. To the extent that the charge here and the record here does not lead you to answer all of the questions you have about the marketplace the Board can if they wish include recommendations for further study, as can the FERC itself. So I think that's an option.
>
> You have certainly made clear what your preference is, and that's subject to further conversation with the Board.[190]

These comments seek to better ensure that further conversations surrounding the affordability of electric service to consumers that result from bid-based SCED in organized markets in the PJM/MISO region does indeed take place. In an effort to collect data from PJM that would allow for independent analysis of the efficacy of PJM market outcomes, the Staff of the Virginia State Corporation Commission ("Staff") has long sought data from PJM that would allow for an unbiased assessment of this crucial aspect of the ultimate impact of PJM operations. Specifically, by letter of September 26, 2005, PJM was requested to provide the following data:

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[189] Tr. February 12, 2006, at p. 44.

[190] Tr. February 12, 2006, at pp. 44-45.

For any given sub-footprint in PJM and starting with the entire PJM footprint, I am interested in the relationship, through time, between day-ahead LMP for any given hour and the actual cost of producing the energy consumed in that hour on both an "as-bid" basis and an as "cost" basis. The cost basis is that developed by generator supplied cost data in PJM's possession. Note that I am not seeking cost data on any particular generating unit, nor am I seeking information that could allow one to decipher cost information regarding any particular generating unit operating in PJM.

In summary, I am requesting that PJM produce hourly calculations for the entire PJM footprint for, say, 2005 year-to-date of:

(1) The "energy bill" for a particular hour equal to the hourly PJM load multiplied by the hourly PJM day-ahead total RTO LMP for that hour;

(2) The cost of supplying energy for that hour (as-bid) calculated as the area under a PJM total RTO supply curve developed from generator bids into the PJM day-ahead energy market; and;

(3) The cost of supplying energy for that hour calculated as the area under a PJM total RTO supply curve developed from generator cost data supplied to PJM by and for generators bidding into the PJM day-ahead energy market.

PJM's response to this request was that such data was not currently available, that PJM was "in the middle of a long-term project[191] to calculate net revenues of every unit for every hour," such data would be made available when the long-term project is complete and that data already available could be used to *estimate* the answer to the question posed. This data has yet to be provided.

The requested information would allow for the development and comparison of the areas represented in the graph described earlier in this comments. Analysis of this data is consistent with the Joint Board's charge to study what constitutes "security constrained economic dispatch," how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned, and to make recommendations to the Commission regarding such issues. The requested data provides a starting point for independent analysis that should shed light on whether competitive wholesale electricity markets continue to deliver the benefits of security constrained economic dispatch that were captured by this industry and delivered to customers prior to restructuring. The requested data should be publicly available. Varied analysis of that data by stakeholders should allow for a free exchange of ideas that can only help this industry move forward in the long-run.

<u>The Generator Net Revenue Issue --- The Fairness Question</u>

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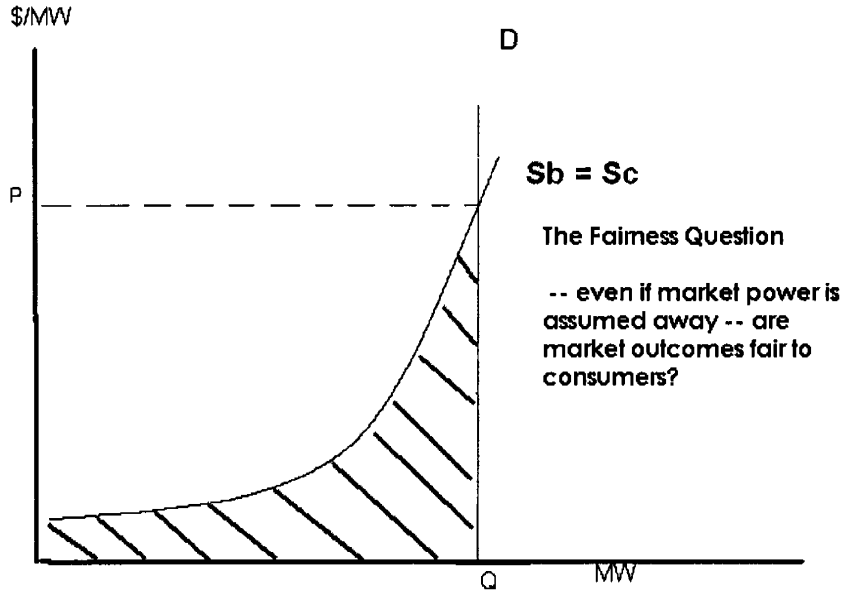
[191] On or about November 11, 2005, PJM stated that such data would be available in the first quarter of 2006. Note that such unit specific data would likely be deemed competitively sensitive. However, such data could be summed by hour. This would answer Staff's question without divulging producer specific information.

On March 22, 2006, PJM responded to a data request of this Joint Board. That data request was propounded to PJM on or about March 8, 2006. While this data request did not specifically ask for the data requested in the September 26, 2005, letter as set forth above, the March 8, 2006 data request asked both PJM and MISO to:

> Please explain whether you share Mr. Spinner's concern about potential divergence between aggregate wholesale electric market prices that result from RTO-managed SCED and aggregate generator production costs. Please provide the relevant data referred to on page 46 of the February 12 Joint Board Transcript.[192]

PJM's March 22, 2006, answer to question #2 includes phrases such as "Mr. Spinner's concerns are not well founded" and "Again, the evidence on net revenues does not support Mr. Spinner's assertions." It bears repeating that while question #2 of the March 8, 2006, data request purports to be somehow related to the above specified data request to PJM contained in the VA SCC staff letter of September 26, 2006, question #2 is not the question that was posed in September. The VA SCC question sought specific data on point to this Board's most important task; question #2 of the March 8, 2006, data request asks the ISOs whether they share the concern of a specific Board member and asks the RTOs to provide any "relevant data" to this issue as it was discussed by the Board. In the case of PJM, that RTO does not appear to share the Board member's concerns nor did it provide any data.[193]

The fairness issue can be illustrated by the following diagram.



Here, market power concerns are assumed away as all offers to sell electric energy into the

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[192] Data Requests from the PJM/MISO SCED Joint Board, March 8, 2006, question #2.

[193] In fact, PJM's March 22, 2006 response for question #2 provides no data at all. PJM's response provides assertions and calculations; the data and assumptions necessary to independently judge those assertions or replicate the calculations was not provided by PJM in their March 22, 2006 response.

competitive market are assumed to be at marginal cost. The graph simply illustrates the result that, when relatively higher marginal cost units set the market price in the single price auction, the actual resource costs to produce electric energy for a particular time period may be small (the cross hatched area) relative to the total bill for electric energy for the time period (P*Q). The point here is, again, that these areas need quantification before key conclusions are drawn as to the efficacy of market outcomes post industry restructuring. PJM has not as yet responded to requests for the information necessary to calculate these areas by supplying the required data as set forth in the VA SCC staff request by letter of September 26, 2005.

Many stakeholders have serious concerns regarding the efficiency and fairness of organized wholesale electric market outcomes and how those outcomes impact consumers. It is possible to posses and express these concerns without asserting that market outcomes are not just and reasonable. The point is that, given the paucity of data available to independent analysts and the corresponding lack of independent studies that purport to show that organized market outcomes in the PJM/MISO region are just and reasonable, this Board cannot make any finding that organized markets in the PJM/MISO region are, in fact, producing results for consumers that optimize customer affordability of electric power. In other words, a reasonable position is that one may express concerns about market outcomes yet assert nothing more than it has thus far been impossible for independent analysts to obtain the data and information necessary to verify RTOs claims that RTO administered markets in the PJM/MISO region produce outcomes that are just, reasonable and consistent with the public interest.

Comment Conclusion

In this matter, the Joint Board is charged with investigating how the operation of the electric energy system affects or enhances the reliability and affordability of service to customers in the PJM/MISO region, and to make recommendations to the Federal Energy Regulatory Commission regarding such issues. Given the lack of data and independent analysis regarding the efficacy and fairness of market outcomes, the Board cannot find that the results of organized wholesale electricity markets practicing security constrained economic dispatch within the PJM/MISO region produce results that are just, reasonable and in the public interest absent further analysis. While further analysis may be deemed beyond the scope of the Board's work or otherwise impossible to complete before the completion of this report, such analysis should be undertaken as soon as practicable. The first step of such analysis ought to be the dissemination of required information to those who seek to study this important question.

Until requested data is produced and subjected to rigorous independent analysis, the Joint Board on Security Constrained Economic Dispatch for the PJM/MISO region should make no finding regarding the how such a mode of operating an electric energy system affects or enhances the affordability of service to customers in the region concerned.

Attachment D

Concurring Comments of Missouri Representative Jeff Davis to the MISO-PJM Regional Joint Board Report
Docket No. AD05-13-000

In response to dissenting comments submitted by Montana Commissioner Greg Jergeson and concurring comments submitted by Virginia Commissioner Howard M. Spinner, the Missouri Public Service Commission submits the following comments on the issue of the ability of the bid-based, uniform clearing price constructs used by the Midwest ISO and PJM in their regional Security-Constrained Economic Dispatch (SCED) to provide benefits (lower energy costs) to consumers. The following summary highlights these comments.

- With respect to lower energy costs for consumers, regional SCED energy markets should be compared to bilateral energy markets in which buyers and sellers make short-term arrangements for off-system energy transactions.
- In both bilateral energy markets and regional SCED markets, absent transmission constraints and transactions costs, perfectly competitive energy markets would exist with resulting uniform clearing prices. However, levels of imperfect competition exist in both bilateral energy markets and regional SCED energy markets primarily due to transmission constraints.
- The comparison between bilateral energy markets and regional SCED energy markets should focus on the costs of implementing and the savings from regional SCED energy markets as measured by the reduction in transactions costs associated with bilateral energy markets coming from first-come, first-served transmission service and requiring bilateral transactions to be at least one-hour transactions.
- The exercise of market power should not be confused with the concept of bidding higher than incremental variable cost. However, the difference between bids and incremental variable costs is an appropriate measure of the degree of imperfect competition that is applicable to both bilateral energy markets and regional SCED energy markets.

1. Putting Concerns of SCED Related Bid-Based, Uniform Clearing Price Constructs in the Proper Context: Wholesale Energy Markets for Off-System Transactions

An issue was raised in the Joint Board for the MISO-PJM regions use of SCED as to whether or not a bid-based system in which a uniform clearing price construct is applied truly results in least cost to consumers. There were two concerns expressed: 1) whether or not generators bid incremental variable energy costs; and 2) whether paying all bidders the marginal bid that clears the market results in consumers over paying for electricity.

These questions are appropriate, but need to be put into the proper context. Specifically,

regional SCED energy markets do not determine the price that consumers pay for electricity. They were not designed to do this, but instead were designed to determine the price at which utilities would exchange off-system transactions of energy in a wholesale market. As such, regional SCED energy markets should be compared to bilateral energy markets in which buyers and sellers make short-term arrangements for these same types of transactions.[194]

2. Describing the Alternative to Regional SCED Energy Markets: Off-System Transactions in Bilateral Energy Markets

An off-system transaction in bilateral energy markets can be described as a situation in which two utilities have evaluated (prior to real-time dispatch) the incremental variable cost of serving their load from their own resources, and if these incremental variable costs are different, one being higher than the other, overall costs can be reduced by substituting incremental energy from the lower cost alternative to replace incremental energy from the higher cost alternative. Such incremental substitutions of energy will result in generation cost savings up to the point where the incremental variable cost of energy is equalized between the two utilities. However, this does not describe how the price at which such a transaction will take place is determined.

a. Bid and Offer Strategies in Bilateral Energy Markets

In a bilateral energy market, potential sellers may take the position that there is no value to their ultimate consumers from selling the energy from the generation units that are devoted to serving those consumers unless the price is above the incremental cost of the energy used to make the sale. Why would potential sellers, even an independent generator, be willing to run additional generation if by doing, all that is received is the variable costs of their incremental energy with zero profit? On the other hand, if potential buyers can save any money by substituting lower cost incremental energy for their own higher cost incremental energy, they are very likely to enter into such a transaction.

These bidding strategies do not mean that sellers have "market power" over buyers.[195] Moreover, if there are several potential sellers in the market, buyers can negotiate to get the best price below their incremental variable costs. Equivalently, if there are several potential buyers in the market, sellers can negotiate to get the best price above their incremental variable costs. In essence, the degree of competition in the bilateral energy market determines the level of the profit margins over incremental variable costs that sellers are able to earn.

b. Bilateral Energy Transactions Under Perfect Competition

If there are many buyers and many sellers, no transmission constraints, and enough time for

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[194] In his comments, Commissioner Jergesen states: "The buyers (ultimately the consumers) will pay that higher price for all load purchased." This simply is not the case. Instead the buyer will pay the SCED price for generation purchased as a substitute for own generation to serve load. The comparison that must be made is how this differs from the price paid under a system of bilateral transactions for the same energy.

[195] Market power for a seller over a buyer occurs when that buyer has only a limited number of alternative sellers from which to choose and these few sellers have a large number of buyers to which they can sell.

full discovery of what buyers are willing to pay and sellers are willing to take, the results would be a uniform clearing price. To explain this result, consider a buyer that has perfect information about all potential sellers' minimum take prices. This buyer would go to the potential seller with the lowest minimum take price and attempt to enter into a deal at that price with the potential seller. But, also assuming that seller has perfect information about all buyers' maximum pay price, there would be no deal because the seller would go to the buyer with the highest maximum pay price and attempt to enter into a deal at that price. In the end, after all buyers and sellers have negotiated sufficiently to obtain complete information of the market, the result in a world of perfect competition would converge to a uniform clearing price. The definition of a uniform clearing price is where potential sellers whose minimum take price is above this uniform clearing price would not receive offers from buyers, as buyers can get a better deal at the uniform clearing price, and potential buyers whose maximum pay price is below this uniform clearing price would not receive offers from sellers, as sellers can get a better deal at the uniform clearing price. In basic economics, the uniform clearing price in a perfectly competitive world is where supply equals demand. However, actual bilateral energy markets never meet the ideal conditions of perfect competition.

c. Bilateral Energy Transactions Under Imperfect Competition

In actual practice, the number of buyers and sellers may be limited by both transmission constraints as well as by the amount of time to discover what buyers are willing to pay and sellers are willing to take.

1) Limited Numbers of Buyers or Sellers: In many instances, transactions are limited to a handful of sellers for a given buyer, or a handful of buyers for a given seller. In such cases, individual transactions are based on the buyer's and the seller's perception of the best price they can negotiate. Economists characterize this market imperfection of few buyers and few sellers as one in which game theory determines the sets of trades and prices, rather than one where a uniform, market clearing price is determined by supply and demand. In such gaming situations it would be rare to find either sellers revealing to buyers their true incremental variable costs for own generation not needed to serve their load or buyers revealing to sellers their true incremental variable costs for own generation needed to serve their load.

In any event, there is no expectation of a uniform market-clearing price across all bilateral transactions. One reason for this is that scarce transmission capacity limits the set of buyers available to a given seller as well as the set of sellers available to a given buyer. In addition scarce transmission capacity results in these limits being unique to each buyer and seller.[196]

2) Limited Time for Price Discovery: Bilateral transactions associated with physical transmission rights are limited to being at least an hour in duration, and many transactions will cover multiple hours of the day. In addition, transactions are limited by available transmission service that is sold to market participants on a first-come, first served basis. Economists characterize these market imperfections as "transactions costs," and the impact is that market

[196] This lack of price uniformity in imperfectly competitive bilateral energy markets may be comparable to the locational aspect of SCED determined locational marginal prices (LMPs).

participants have limited time for price discovery. Because of these transactions costs, there is no expectation in bilateral markets of a uniform clearing price, even when such transactions take place at a trading hub. Trading hubs were designed to help provide a way for buyers and sellers to more quickly discover prices, but still allow for individual (bilateral) transactions.[197] But even with improved price discovery through such trading hubs, bilateral energy markets transactions require physical transmission service, which when sold to market participants on a first-come, first-served basis puts additional time pressure on market participants to make their deal and reserve the transmission service as quickly as possible. When choices are limited on a non-economic basis (i.e., first-come, first-served), the result will not be a uniform clearing price.

3. Comparing Regional SCED Markets to Bilateral Energy Markets

It is important to point out that the Federal Energy Regulatory Commission moved away from cost-based transactions (e.g., marginal cost plus 10% adder) to market-based transactions for utilities that could demonstrate a lack of market power, and this change exists for bilateral markets as well as for regional SCED markets. Thus, while a comparison of cost-based transactions to bid-based transactions may provide some measure of the degree of market imperfections, such a metric would beequally applicable to both bilateral and regional SCED markets, but is not reasonable as a measure of comparison between the two types of markets unless it is measure for both.[198]

a. Regional SCED Markets Are Designed to Eliminate The Transaction Costs Found In Bilateral Energy Markets

Since SCED markets allow bids and offers to be submitted by potential buyers and sellers, it would be unrealistic to assume that such markets are designed to eliminate the market imperfections that occur in bilateral markets where buyers and sellers also have the freedom to submit bids and offers. Thus, the issue of lowering costs to consumers related to SCED markets is the extent to which such markets reduce transaction costs.

b. Potential Savings in Transactions Costs from Regional SCED Markets

With the focus of regional SCED being the elimination of market transaction costs, there are potentially two forms of potential savings for consumers. First, instead of limiting potential sellers available to a buyer by the available physical transmission capacity sold on a first-come, first-served basis, SCED puts all buyers and sellers on an equal footing and allocates scarce transmission on the basis of bids and offers submitted. Notice, whether a market participant is a buyer or a seller is determined on the basis of generation bids submitted. In this context, a buyer is a market participant whose own generation that is either scheduled or sold into the market is

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[197] Trading hubs deal in multiple hour products such as a fixed megawatt level over the on-peak hours.

[198] Commissioner Spinner's comments indicate that comparing bids to incremental costs is a "meaningful exercise" because bids higher than incremental costs mean higher costs to consumers, but higher costs in comparison to what? Certainly not in comparison to bilateral markets where similar bidding and offer strategies occur.

less than its load, and a seller is a market participant whose own generation that is either scheduled or sold into the market is greater than its load.[199] By eliminating the time constraint of the first-come, first-served construct of physical transmission reservations, SCED increases the number of transactions of utilities with higher incremental energy costs buying from utilities with lower incremental energy costs; at least to the extent that the transmission system is able to deliver the lower incremental cost energy to the buyers. Which potential sellers get to use the limited capabilities of the transmission system depends on location of the generation and having the lowest bids, not on who is able to submit a request for transmission service at the earliest time.

Second, instead of limiting transactions to being no shorter than one-hour in duration, both MISO and PJM have five-minute dispatches. This allows for a greater level of granularity in decisions about adding the lowest bid generation when load is increasing throughout the hour, or cutting back on the highest bid generation when load is decreasing throughout the hour. With a minimum time frame of one-hour on bilateral transactions, increases or decreases of generation within the hour will not capture the within hour savings available from a five-minute dispatch.

These savings that result from reducing transactions cost do not necessarily mean that regional SCED markets are cost beneficial. Regional SCED markets are expense to operate and these costs should be compared to the benefits that are likely to result from reducing the transactions costs associated with bilateral energy markets. However, the focus should be on proper measurements of the costs and the savings that result from reducing transactions costs and not on the degree of imperfect competition that exists in both types of energy markets.

4. Comparisons of Market Power and Levels of Imperfect Competition

First, it should be pointed out that while the level of bids above incremental cost is a measure of market imperfection (due to transmission constraints), it is not necessarily a synonym for what FERC defines as market power.

a. Measures of Market Power

Market power is the ability of a market participant to influence the price through either economic or physical withholding of generation from the market. Economic withholding is not solely the ability of a seller to offer a price higher than its incremental variable cost in an effort to make a profit when its sells into the market. Instead, economic withholding applies when a market participant expects that a certain block of energy will set the price at which other lower incremental cost energy from that same market participant are likely to sell. The strategy for economic withholding is to offer a price on this marginal block of energy high enough that it is excluded from the market, resulting in the market price being set at a higher price that is then paid to other energy being sold by that same market participant into the wholesale market. Thus, economic withholding is both a question of bid above incremental variable cost as well as the

[199] Of course, generators without contracts to serve load would always be sellers. But to the extent that a load-serving entity has generation resources adequate to cover its load and operating reserves, it could be either a buyer or a seller, and this would only be on the margin.

placement of the bid with respect to market conditions.

The extent to which market power exists is difficult to discover in a bilateral transactions market where bids are confidential. Because of this, FERC has used safe-harbor tests as a method to screen out instances where the potential to exercise market power is very unlikely. If a market participant does not pass this screen in a specified market area, then it must either provide detailed pricing information to prove its lack of market power or submit to mitigating its market power through some form of cost-based pricing.

For regional SCED energy markets, FERC has approved Independent Market Monitors (IMMs) to have access to bids submitted by generators. Clearly, IMMs can estimate the degree to which these bids vary from incremental cost and the market conditions under which such bids are submitted, and this can be used to help detect the exercise of market power. Thus, SCED energy markets may provide some additional disincentives for market participants to exercise market power. However, it is important to note that this hypothesis of additional disincentives would be difficult to verify empirically as data on bids and offers from bilateral energy markets are not available and probably, do not exist. Without empirical verification, it is not correct to assume that market power is reduced simply by the existence of a regional SCED market.

b. Measuring Imperfect Competition: Bids Above Incremental Variable Cost

The degrees to which bids exceed incremental variable costs are an appropriate measure of market imperfections. For example, if bids only exceed incremental variable costs in the range of up to 10% (the old FERC standard for cost-based pricing of off-system sales), it could be argued that the regional SCED energy markets are highly competitive. This high of a level of competition is not likely to occur because of the limitations of transmission constraints. It is worth repeating that the limitations of transmission constraints exist in both bilateral energy markets and regional SCED energy markets. While it might be argued that by reducing transactions costs, regional SCED energy markets also have some impact in reducing the level of imperfect competition by expanding the level of overall transactions, this hypothesis would be difficult to prove empirically.

c. Correcting Imperfect Competition: Expanding Transmission

Beyond using the difference between bids and incremental variable costs as a measure of the degree of imperfect competition due to transmission constraints, the MISO and PJM should addressed the reduction in the difference between bids and incremental variable costs that can be achieved through the expansion of the existing transmission system.[200]

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[200] Currently, the Midwest ISO's method for measuring the benefits from transmission expansion focus on the savings that result from expanding the volume of transactions and the decreases that occur in LMPs. Moreover, the bidding behaviors of market participants assumed is that market participants always bid their incremental variable costs. Competitive benefits from expanding transmission could be estimated by comparing the relationship between bids and incremental variable costs in sub-regions and hours where transmission constraints do not result in transmission congestion to sub-regions and hours where transmission constraints result in transmission congestion.

Appendix E: South Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Study and Recommendations Regarding Security Constrained Economic Dispatch

By

The Joint Board for the South Region

July 11, 2006

I. Overview

The South Joint Board for the Study of Security Constrained Economic Dispatch is one of four joint boards designated by the Federal Energy Regulatory Commission ("Commission" or "FERC") under EPAct2005, Section 1298, Economic Dispatch. The members of the South Joint Board are:

> Chairman Joseph T. Kelliher, Federal Energy Regulatory Commission, Chair of the Joint Board
> Commissioner Sam J. Ervin, IV, North Carolina Utilities Commission, Vice Chair of the Joint Board
> President Jim Sullivan, Alabama Public Service Commission
> Chairman Sandra L. Hochstetter, Arkansas Public Service Commission
> Commissioner J. Terry Deason, Florida Public Service Commission
> Ms. Pandora Epps, Internal Consultant, Georgia Public Service Commission
> Chair Brian J. Moline, Kansas Corporation Commission
> Commissioner James M. Field, Louisiana Public Service Commission
> Dr. Christopher Garbacz, Director, Economics and Planning Division, Mississippi Public Utilities Staff, representing the Mississippi Public Service Commission
> Commissioner Steve Gaw, Missouri Public Service Commission
> Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
> Chairman Jeff Cloud, Oklahoma Corporation Commission
> Vice Chairman G. O'Neal Hamilton, South Carolina Public Service Commission
> Mr. Pat Miller, Director, Tennessee Regulatory Authority
> Commissioner Julie Caruthers Parsley, Public Utility Commission of Texas

The South Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 12, 2006 in Washington D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1) "to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report is divided into four sections. The first, Security Co nstrained Economic Dispatch: the Basics, provides a description of the basic concept of Security Constrained Economic Dispatch used in the study; the second, Economic Dispatch in the South, describes dispatch procedures in the South; the third summarizes the issues raised and considered by the board, including any recommendations made by individual board members or other parties to address these issues; and the fourth section discusses the

recommendations of this Joint Board. The principal sources for these sections are presentations to the board and written comments submitted to the board, discussions among the Joint Board members, the Department of Energy (DOE) report under EPAct 2005, section 1234, and the responses to the DOE survey of economic dispatch.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of Security Constrained Economic Dispatch (SCED): "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[1] This definition describes the basic way all utilities in the region dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and season; the costs of generation from different types of units vary greatly; and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. Security constrained economic dispatch is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating characteristics, such as how quickly output can be changed, maximum and minimum output levels, and the minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and the cost of environmental compliance.

In addition, forecast conditions that can affect the transmission grid must be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, line capacities as affected by loading levels and flow direction, and the weather. If the security analysis indicates that the optimal

[1] September 30, 2005 order at P14.

economic dispatch cannot be carried out reliably, relatively expensive generators may have to replace cheaper units.[2] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure flows stay within reliability limits and voltage within reliability ranges. If transmission flows exceed accepted limits, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes.

The manner in which transmission and operational limitations of generators have been represented in unit commitment and economic dispatch software has not been uniform across the industry. For example, some unit commitment software packages might represent the entire transmission network in detail, while others might only represent selected transmission constraints to make the problem easier to solve. Similarly, the representation of unit operational constraints and in some cases even the network model might vary in economic dispatch software. Generally, however, advances in hardware and software (e.g., the use of mixed integer programming for unit commitment) now make it technologically feasible to undertake security constrained economic dispatch over large regions.

Aside from differences in the models used in economic dispatch software, questions have been raised about the extent to which all available resources are appropriately considered in the dispatch process. It has been alleged by some, but certainly not all, of the participants in the Joint Board process that various factors, including perceived limitations in utility open access transmission tariffs, have made it more difficult to ensure that all available resources are appropriately included in the dispatch process.

III. Economic Dispatch in the South

The practice of economic dispatch in the South varies by utility and region. In most of the South, economic dispatch is performed on a system-by-system basis. In Texas it is performed on a regional basis through replacement of utility control areas with a central

[2] This is known as "out of merit" dispatch.

market operator, and the Southwest Power Pool is proposing its own form of a regional economic dispatch in the form of a balancing market. Even though the South utilizes the same basic concept of next day unit commitment and real-time security constrained economic dispatch processes described in the prior section, there are variations in the implementation details as described below.

In addition to day-ahead unit commitment, Duke performs resource commitment studies over a seven-day period because of a large concentration of pumped storage generation in its portfolio.[3] Due to the nature of pumped storage generation, Duke needs to look not just at the forecasted conditions for the next day but also the expected conditions over the next week to determine the most effective way to operate those units. Duke also includes third party resources in its commitment and dispatching processes through its bulk power marketing function that is responsible for purchasing economic power.[4] In addition, Duke is implementing an Independent Entity for performing certain Open Access Transmission Tariff functions and an Independent Monitor for monitoring its transmission.

Entergy performs economic dispatch for its footprint in Arkansas, Louisiana, Mississippi, and Texas with a diverse generation resource portfolio and bilateral contracts for power purchases from non-utility generators. In addition to next day unit commitment, Entergy has broadened its use of market purchases in its commitment and dispatching processes through a Weekly Procurement Process to include independent power producers and other utilities.[5]

Southern Companies perform economic dispatch under a pooling arrangement for the generating resources controlled by its operating companies in Alabama, Georgia, Mississippi and Florida.[6] Each operating company makes its generating resources exclusively available for economic dispatch by the pool. The generation portfolio consists of diverse fuel type generation, and purchase power agreements with non-utility generators and other market participants through Southern term traders. [7]

Members of the Southwest Power Pool are considering implementing an Energy Imbalance Market within the SPP footprint. SPP will perform a real-time security constrained economic dispatch of the entire market footprint without respect to control areas. Currently, however, economic dispatch is performed individually by multiple control areas located in the SPP footprint. Each owner of generation performs its own economic dispatch for its portfolio of resources including generation, transactions, and

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[3] Mr. Scott Henry – Duke, Transcript of Nov. 13, 2005 Board meeting, tr at 22.
[4] Id. at 26.
[5] Mr. Hurstell – Entergy, tr at 28.
[6] Alabama Power Co., Georgia Power Co., Gulf Power Co., Mississippi Power Co., and Southern Power Co.
[7] Mr. Graham, Jr. - Southern Companies filing comments, page 6.

demand side management.[8]

Economic dispatch in the Florida Reliability Coordinating Council is performed by eleven Balancing Authorities, (formerly referred to as control areas) through their own economic dispatch energy management system. This optimizes production costs for the balancing authority resources that are supplemented with wholesale "market" sales and purchases through bilateral transaction activity, including both utility and non-utility generation. One balancing authority in the region also acts as a "power pool" for its members.[9]

ERCOT is the only organized market currently operating in the South region. It was organized out of 10 control areas. In ERCOT there are two entities responsible for the dispatch of the system: qualified scheduling entities (QSEs) and ERCOT.[10] QSEs perform commitment and dispatch processes by both taking into account their portfolios and any other offers on the bilateral markets. ERCOT will then modify or supplement that dispatch to meet total system load, maintain system frequency and manage transmission congestion if necessary.

ERCOT meets its system needs by using ancillary service capacity and running a balancing energy market every 15 minutes, allowing all generation, regardless of ownership, to bid and provide balancing energy. ERCOT manages transmission congestion with zonal and intra-zonal type arrangements. ERCOT is moving toward nodal pricing, which will allow it to perform centralized day ahead commitment and economic dispatch processes based on bid prices.

IV. Issues

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues suggested in the record. This section also discusses the recommendations from the DOE report to Congress on the value of economic dispatch.

Below are the issues raised by utilities, independent power producers, market participants and transmission dependent utilities:

- Inclusion of non-utility generation in the dispatch
- Coordination of economic dispatch for all loads
- Independence of dispatcher
- Transparency of dispatch information and processes

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[8] SPP: Stakeholder Panel - South filing comments, page 1.
[9] Florida Reliability Coordinating Council responses to DOE survey.
[10] Mr. Saathoff - ERCOT, tr at 63.

- Market liquidity
- Transmission constraints
- Regional transmission planning and expansion

Inclusion of non-utility generation in the dispatch.

In general, the majority of vertically integrated utilities in the region state that the current unit commitment and real–time economic dispatch processes are working fine and benefiting ratepayers in their areas.[11] Their unit commitment processes provide opportunity for third-party generation resources to participate through bilateral contracts in block offers to the extent that those resources elect to be included.

Independent power producers, market participants and transmission dependent utilities state that not all generation resources within vertically integrated utilities' footprints are included in the economic dispatch process. Non-utility generators say that dispatching only generation resources owned by one entity and purchasing power through bilateral contracts does not suggest that the system as a whole is economically dispatched nor does it suggest that the consumers are receiving energy at the least possible cost.[12] If the commitment and dispatch processes do not include all generation resources in a region, then load cannot have access to the most economic power and use of the transmission system will not be optimized. They suggest that including all generation resources regardless of ownership within each utility's footprint and in a broader region would be beneficial to consumers in the entire region.

Some observers say that a reason third-party generation resources are not included in the near real-time economic dispatch is because those resources are incapable of providing sufficient operational flexibility for regulation.[13] In addition, one utility argues that including all generators, regardless of ownership, into the economic dispatch would strip the states of their power to control whether their retail customers received the lowest cost energy and could decrease reliability because some of those generators probably would not be creditworthy.[14]

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[11] Mr. Scott Henry – Duke, tr at 26.
Mr. Hurstell - Entergy, tr. at 32.
Mr. Graham, Jr. – Southern Companies filing comments, page 20.

[12] Mr. O'Connell – Williams, filing comments, page 3.
Ms. Turner - Union Power, filing comments page 2.
Mr. Sam Henry – SUEZ filing comments, page 1.

[13] Mr. Scott Henry - Duke, tr at 27.
Mr. Hurstell - Entergy, tr at 29.
Mr. Graham, Jr. – Southern Companies filing comments, page 16.

[14] Id., page 16.

Coordination of economic dispatch for all loads.

Transmission dependent utilities[15] in the South are concerned that there is no coordinated economic dispatch that covers all loads within a utility's footprint. With Entergy's Weekly Procurement Process, the dispatching utility can take advantage of independent resources of its choosing to serve its own load, but the transmission dependent utility's network customers do not benefit from the process. Furthermore, during the Weekly Procurement Process, the available flowgate capacity determination process for other transmission customers is closed down for about half a day, while the optimization analysis is being performed for the dispatching utility. Other transmission customers seeking alternative resources cannot have transmission reservation requests processed during this "blackout" period, and are able to use only available flowgate capacity that is left after the dispatching utility completes its resource selection.[16] This makes it difficult, especially for entities that are transmission dependent, to efficiently utilize their own resources and prevents them from taking advantage of efficiencies in a broader wholesale market.

Independence of dispatcher.

In addition to suggesting that all generation resources should be included in the economic dispatch process in order to improve benefits to consumers, non-utility generators further recommend that an independent organization should be responsible for implementing and operating the commitment and dispatch processes. An independent administrator will utilize the most efficient resources available regardless of ownership and optimize transmission capacity by sharing real-time information between the dispatcher and the market participants. It also eliminates any suspicion that transmission owners favor their own resources over those of other stakeholders.[17] One utility argues that this Joint Board is not the forum to discuss whether an independent entity should regionally operate the transmission in the South.[18]

Transparency of dispatch information and processes.

One utility argues that there is significant transparency in the transmission information posted on Open Access Same Time Information System ("OASIS"), including information pertaining to Total Transfer Capacity, Available Transfer Capacity, and

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[15] Mr. Priest – MDEA (Mississippi Delta Energy Agency), tr. at 34.
Mr. Beam – NCEMC (North Carolina Electric Membership Corp), tr at 38.

[16] Mr. Priest – MDEA, tr at 36.

[17] Mr. O'Connell – Williams, filing comments, page 4.
Ms. Turner - Union Power, filing comments, page 7.
Mr. Sam Henry – SUEZ filing comments, page 2.

[18] Mr. Graham, Jr. - Southern Companies, filing comments, page 20.

transmission studies.[19] However, independent power producers argue that an independent administrator will provide transparency of prices, allocation of transmission capacity and transmission congestion management through published business rules, interpretations and curtailment events.[20] The lack of visibility into transmission loading events hampers their ability to respond because they do not know whether making a certain adjustment will result in helping or hindering the particular problem that the dispatching utility is addressing. The other issue that hampers them in performing economic dispatch is that their plants do not get access to the control signals necessary to perform certain functions, such as regulation.[21]

Market liquidity.

One transmission dependent utility contends that the South region has a very illiquid market for economic transactions.[22] Utilities still rely on phone calls for potential trading because there is no central clearinghouse, making it an inefficient system for optimizing resources at the lowest cost. One independent power producer argues that trading hubs in the South are less liquid than other hubs because they lack transparency regarding transmission congestion management, transmission system operation, and price information. Limitation on transmission capacity is also a contributing factor.[23]

Transmission constraints.

Because of transmission limitations in the South, transmission dependent utilities and the Southwest Power Pool[24] say that the biggest impediment to economic dispatch is constraints on the transmission system. Transmission constraints can prevent efficient generation resources from being dispatched. These parties say they are frequently unable to access economic sources because of transmission limitations and often forgo economic transactions because of a concern that the transaction could be curtailed.

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[19] Mr. Graham, Jr. – Southern Companies, filing comments, page 12.
[20] Mr. O'Connell – Williams, filing comments, page 4.
Mr. Sam Henry – SUEZ, tr at 45, 46.
[21] Mr. O'Connell – Williams, tr at 52, 53.
[22] Mr. Beam – NCEM, filing comments, page 2.
[23] Mr. O'Connell – Williams, tr at 77,78.
[24] Mr. Beam – NCEMC, tr at 40.
Mr. Monroe – SPP, filing comments, page 2.
Mr. Sam Henry – SUEZ, filing comments page 2.

Regional transmission planning and expansion.

Transmission dependent utilities suggest that transmission infrastructure in the South should be strengthened. One transmission dependent utility[25] states that regional planning and operation of the electric system beyond traditional control area boundaries are necessary to resolve many of these problems without mandating an RTO structure. For example, load-serving entities in North Carolina, in cooperation with the North Carolina Utilities Commission, recently established a collaborative transmission planning process to jointly plan the transmission system for network customers. The Southwest Power Pool also states that, without adequate regional transmission planning to expand and upgrade the capacity of transmission grid, economic dispatch cannot fully sustain its promised benefit.[26] Although members of the South Joint Board did not reach unanimity as to the desirability or importance of independent review of transmission projects, some members of the South Joint Board contend that having an independent entity review transmission projects helps to ensure that regional transmission plans are developed in a non-discriminatory manner so as to optimize security constrained economic dispatch.

One utility argues that without participant funding or direct assignment of costs, expanding the transmission system so that all generators within the system can be incorporated into economic dispatch would be prohibitively expensive and place an undue burden on retail customers.[27]

V. Recommendations of the Joint Board

The members of the South Joint Board agree, consistent with the conclusions reached in the Department of Energy survey, that there is no single appropriate method for performing economic dispatch and that the nature of economic dispatch can appropriately vary from region to region across the country depending upon variations in local conditions, including, but not limited to, the degree to which the industry remains vertically integrated, the presence or absence of bid-based organized markets, the manner in which retail rates are established, and similar factors. For example, dispatch is performed differently in the ERCOT region of Texas than it is in those portions of the region not served by an organized market, but the mere existence of those differences does not establish that either portion of the region fails to engage in security constrained economic dispatch.

The members of the South Joint Board unanimously agree that utilities operating in the region should engage in security constrained economic dispatch. However, economic dispatch is performed differently in ERCOT than in the remainder of the South, where

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[25] Mr. Beam – NCEMC, tr at 41.

[26] Mr. Monroe – SPP, filing comments, page 3.

[27] Mr. Graham, Jr. – Southern Companies filing comments, page 12.

generation is dispatched on an individual system basis at the present time. The members of the South Joint Board conclude that utilities in the South are engaging in security constrained economic dispatch to the extent that they operate consistently with the procedures that the utilities described to the Joint Board. Some members of the South Joint Board are concerned about the efficacy of the results that occur when dispatch is performed by the utility outside the context of an organized market or in situations not including an independent operator due to a perceived lack of transparency. The members of the South Joint Board agree that state regulatory oversight of utilities helps to ensure that such utilities do, in fact, perform security constrained economic dispatch. In addition, the members of the South Joint Board conclude that the work of the Joint Board is limited to examining issues relating to "security constrained economic dispatch" and that other forms of dispatch, such as environmental or efficient dispatch, are beyond the scope of the Joint Boards' assignment.

Some members of the South Joint Board believe that, in areas that lack organized wholesale markets, it becomes difficult to determine whether or not all available resources are appropriately included and dispatched and therefore, that cost effective markets can contribute to the operation of generation facilities to produce energy at the lowest cost. Other members of the South Joint Board believe that there are legitimate questions as to the cost-effectiveness of organized wholesale markets, the extent to which transactions in such markets are priced appropriately, the extent to which bid-based pricing of the type characteristic of such organized markets results in the dispatch of the lowest cost generation to meet customer load and the difficulty of overseeing the appropriateness of dispatch in the absence of such markets. As a result, the South Joint Board did not reach a conclusion on the value of organized wholesale markets in ensuring that the lowest cost available resources are actually being dispatched to serve end-user customers.

Although the members of the South Joint Board conclude that security constrained economic dispatch is performed across the region in varying ways, the Joint Board recognizes that a number of different issues were raised during the initial meeting of the Joint Board and in the comments submitted to the Joint Board that are worthy of further discussion. One of the principal tasks committed to the membership of the regional FERC/State Joint Boards is to make recommendations to the Commission concerning possible improvements to economic dispatch in each region. The suggestions made during the initial South Joint Board meeting and in the comments submitted following that meeting were intended to assist the members of the South Joint Board in developing such recommendations. The members of the South Joint Board appreciate the time and effort that went into the presentations made by all participants during the initial Joint Board meeting and the comments that have been submitted to the Joint Board since that time. These presentations and comments raise a number of issues which the members of the South Joint Board have carefully considered in the formulation of our conclusions and recommendations.

Among the suggestions for improving economic dispatch in the South were that a trading hub with a day ahead market, an energy broker system such as that previously used in Florida, or an automated interchange matching system similar to the one that existed during the 1990s be established in the region. In view of the manner in which economic dispatch is performed in the portion of Texas served by ERCOT, the members of the South Joint Board assume that this recommendation applies exclusively to the portion of the region outside ERCOT. As the members of the South Joint Board understood these proposals, the proposed improved trading hub, energy broker system, or automated interchange matching system would be voluntarily established and open to any market participant that wished to purchase or sell power using the facilities made available by these arrangements. The purpose of such trading hubs would be to improve the liquidity and price transparency associated with bilateral transactions in certain portions of the region. The members of the South Joint Board agree that there might be some benefit to the establishment of such an expanded trading hub, energy broker system, automated interchange matching system, or some similar mechanism as long as market participants have confidence in the transparency and evenhandedness with which such an institution was operated (whether through independent management or some other mechanism) and as long as such an institution produces cost-effective purchase and sales opportunities without creating additional reliability or congestion issues. Subject to those caveats, the members of the South Joint Board encourage market participants to give further consideration to the development of such arrangements.

In addition to proposing the establishment of an improved trading hub or similar processes, participants in the Joint Board process also suggested that the scope of economic dispatch be expanded. As a result of the approach to economic dispatch employed in the ERCOT portion of Texas, and the energy imbalance market scheduled for operation in SPP in the fall of 2006, members of the South Joint Board believe that this recommendation is applicable to that portion of the region outside ERCOT and SPP. Although the nature and extent of the proposals for expanding the scope of economic dispatch in the region advanced to the Joint Board were not described in detail, some members of the Board believe that the adoption of such proposals could, depending upon the manner in which they were implemented, fundamentally alter the manner in which electric service is provided in some parts of the South, disturb settled customer expectations, and result in significant shifts in jurisdiction and customer costs. Other members of the South Joint Board believe that the implementation of such an expanded dispatch could result in lowering overall generation costs and produce savings for retail customers. In order to implement such a proposal, it would appear to the members of the Joint Board that a Regional Transmission Organization (RTO) or some independent third party dispatch operator would be required. Some members of the South Joint Board are concerned that the institution of an RTO or similar institutions in their states would result in a loss of State jurisdiction and could increase customer costs. Some members of the South Joint Board believe that RTO or independent third-party dispatch creates greater wholesale price transparency and could result in lower customer costs. The FERC's belief (which is shared by many State members) is that such institutions should only be

established on a voluntary basis. The State members of the South Joint Board believe that existing law requires that the implementation of such proposals be subject to State review and approval in order to ensure their cost-effectiveness. As a result, the members of the South Joint Board do not recommend that an expanded regional dispatch be involuntarily implemented in the South at this time. As is always the case, however, the members of the South Joint Board encourage market participants and others to continue to investigate alternatives that would reduce the cost and improve the reliability of electric service for customers within the region.

Certain participants in the Joint Board process recommended that additional transparency be created with respect to the operation of the transmission system and transmission congestion management in the region and that the capacity of the existing transmission system be expanded. Although these proposals are interrelated and could apply throughout the region, including the area served by ERCOT and the Southwest Power Pool, the members of the South Joint Board will address them individually, given that these proposals raise several different issues and could be resolved in differing ways.

The members of the South Joint Board favor appropriate, cost-effective, improvements in the transparency with which the regional transmission system is planned and operated and the manner in which transmission congestion is managed. The efficacy of existing economic dispatch procedures in the region, which rely heavily on bilateral transactions, rests on the assumption that load serving entities have non-discriminatory access to potential suppliers. Users of the transmission system for the purpose of participating in wholesale transactions should receive non-discriminatory transmission service in a manner consistent with the Open Access Transmission Tariff (OATT) and existing market rules. However, issues have been raised about the adequacy of the manner in which the OATT has been implemented and enforced in many parts of the country. For that reason, some of the State members of the South Joint Board have expressed support for the Commission's decision to reexamine the existing OATT in order to ensure that any needed improvements are made and any important issues are addressed. The members of the South Joint Board assume that OATT-related issues will be appropriately addressed in the ongoing Commission proceeding relating to the revision of Order 888 and see no need to further comment on those issues as part of the activities of this Joint Board. Furthermore, the nature of the proposed improvements in the manner in which the transmission system in the region is planned and operated and the manner in which transmission congestion is resolved were sometimes not clearly stated. In the event that the proponents of these improvements in transmission system operation contemplate the creation of an RTO or a non-RTO independent entity or process, the members of the South Joint Board conclude that such a step may or may not be appropriate depending on the circumstances, that market participants should feel free to explore the creation of such institutions or alternative approaches, and that proposals for the creation of such institutions should be handled consistently with federal and state law to assure that they are cost-effective and serve the public interest.

As the members of the South Joint Board understand the term, the issue of transmission system expansion may or may not go beyond the scope of an examination of security constrained economic dispatch of the type contemplated by Congress. On the one hand, some members of the Joint Board believe that the inquiry contemplated by Congress takes the capacity of the existing transmission system as a given and proposes an examination of how available generating units should be dispatched in the most economic manner possible given these system limitations. Other members of the South Joint Board believe that issues relating to the expansion of the system are well within the Joint Board's purview as described by Congress. The members of the South Joint Board were not able to achieve unanimity with respect to this legal issue. Regardless of the conclusion which individual members of the South Joint Board reach with respect to this issue, the adequacy of the transmission system in the region clearly affects the ability of load serving entities to utilize or procure energy from certain suppliers and is, for that reason, related to system dispatch issues on a longer-term basis. The members of the South Joint Board further agree that it would be beneficial to obtain improved information about actual expansion of the regional transmission system, including the size, location, and purpose of proposed expansions. In addition, the members of the South Joint Board agree that the obligation imposed upon all regulated utilities to provide adequate service includes appropriately planning for the cost-effective expansion of the transmission system to meet the needs of end user customers in the most reasonably-priced and equitable manner possible. Finally, the members of the South Joint Board believe that issues relating to the expansion of the transmission system should be resolved in a manner that is equitable and cost-effective and that respects appropriate jurisdictional boundaries as is required by existing federal and state law.

Various participants in the Joint Board process recommended the establishment of independent transmission coordinators or similar entities to optimize transmission planning for both reliability-related and economic expansions, to monitor market conditions and behavior, and to oversee system operations. As a result of the role in planning and system operation played by ERCOT and SPP, the members of the South Joint Board assume that these proposals relate primarily to the portion of the region not served by the two existing RTOs. Most areas in the South region outside ERCOT and SPP rely upon traditionally-regulated, vertically integrated utilities with a statutory obligation to provide service in defined service territories. The primary duty that these utilities are required to perform is providing reliable service at just and reasonable rates to native load customers. Although these utilities are solely responsible for planning and operating their own systems, they are interconnected with adjoining utilities and work with their regional neighbors to some degree in order to plan and operate the transmission system. The coordination of planning and operations among such utilities is becoming more formal and interdependent through voluntary action on the part of the affected utilities.

A considerable amount of work on proposals for improving the planning and operation of the transmission system is currently occurring within the region. These initiatives make

transmission planning and operation more independent from the utility company owning the transmission. For example, the Commission has recently approved Entergy's ICT proposal and Duke Power's Independent Entity proposal. Similarly, the load serving entities in North Carolina have agreed upon a joint planning process that they hope will lead to improvements in transmission planning there. Some members of the South Joint Board believe that an independent transmission planning process is required to assure that transmission upgrades and other improvements occur on a non-discriminatory basis. In addition, some members of the South Joint Board believe that specific proposals for independent transmission planning should be subject to State review for cost-effectiveness as a precondition for their implementation. Although the members of the South Joint Board disagree on the need for or desirability of an independent transmission planning process, they do agree that interested parties should continue to explore such alternatives on a voluntary basis and to seek appropriate regulatory redress in the event that they possess evidence of inappropriate conduct by any market participant. The members of the South Joint Board also conclude that the formation of such entities should be encouraged where their activities would be cost effective, beneficial to customers, and not diminish reliability and that their formation should be voluntary rather than mandatory and subject to any applicable state rules, regulations, and statutes.

Among the recommendations advanced in the study of economic dispatch issues performed by the United States Department of Energy was the suggestion that the Joint Board review selected dispatch entities, including some investor-owned utilities, in order to determine exactly how they conduct economic dispatch. According to the DOE study, such reviews could document the reasons for any departures from pure least-cost dispatch so that one could ascertain whether such deviations resulted from entity-specific or regional business rules, on the one hand, or reliability, regulatory, and environmental constraints, on the other. The members of the South Joint Board believe that conducting such a study in a dispassionate, fact-based manner might resolve some of the issues that were raised by various participants in the Joint Board process and would tend to be supportive of the performance of such a study. However, it is not clear to the members of the South Joint Board how much data would need to be obtained in order to conduct such a review, how much time and expense would be involved in the review process, and how such a study would be paid for. As a result, the members of the South Joint Board conclude that such a review should be undertaken by an appropriate body in the event that the cost of such a review is determined to be reasonable, the funding source is clearly identified, the necessary data is readily available in filings with state or federal agencies, and the purpose and scope of the review is agreed upon by all parties at the beginning of the review process.

Furthermore, the DOE recommended that the Joint Boards explore various proposals for more standardized contract terms associated with wholesale power transactions and engage in further study of current economic dispatch technology tools. The members of the South Joint Board believe that further exploration of these issues could be helpful. However, any such exploration should be undertaken with the understanding that

adequate flexibility in wholesale contracting should be preserved in the interests of assuring the most economical service for customers, that the data necessary to undertake these explorations should be reasonably available before such a study is undertaken, that the costs of these reviews should be reasonable, and that any review of such standardized contract terms and dispatch technology tools should have a specific, widely-accepted scope and set of specific objectives sought to be accomplished.

CODA

The record contains expressions of concern about the extent of the willingness of vertically integrated utilities to purchase power from unaffiliated generators even when it is economically appropriate to do. The vertically integrated utilities argue in response that they do not hesitate to purchase power from any available source that can supply power on an economic basis. The Joint Board process created by Congress does not allow the members of the South Joint Board to resolve this apparent factual dispute since it does not involve the use of formal hearing procedures. The members of the South Joint Board note that, in many States where vertically integrated utilities continue to exist and are subject to state regulation, State commissions or State commission staff have the authority to oversee utility dispatch decisions and to disallow costs incurred as the result of a failure to purchase the most economical power. However, the information on potential bilateral energy transactions available to state commissions may be subject to certain limitations. Specifically, data on potential transactions not pursued by the utility may not be routinely retained in the absence of an order to the contrary. In addition, under certain circumstances, claims alleging undue or unreasonable discrimination by regulated utilities can be presented to either the FERC or a State commission. The members of the South Joint Board conclude that there is some degree of recourse available to entities that believe that security constrained economic dispatch is not being performed in an appropriate manner and that entities with evidence that security constrained economic dispatch is not being performed properly should not hesitate to bring such claims to the appropriate regulatory body for redress in accordance with law. Some members of the South Joint Board believe that it may be difficult for a regulatory body to determine whether actionable discrimination has occurred in the absence of the transparency that they believe to be inherent in organized markets or the use of an independent operator. However, as has been noted above, the members of the South Joint Board have differing opinions as to the value of such institutions. Those Joint Board members that are supportive of cost effective organized markets and similar institutions believe that they improve the ability of regulators to evaluate the credibility of such allegations. Those Joint Board members that are not convinced of the value of such institutions are skeptical of the usefulness of any information that is allegedly available in such markets given limitations on available resources and do not believe that organized markets or similar institutions are necessary to permit a determination as to whether actionable discrimination has occurred.

Appendix F: West Joint Board Final Report

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Joint Boards on Security Constrained Economic Dispatch	))	**Docket No. AD05-13-000**

Study and Recommendations Regarding Security Constrained Economic Dispatch

By

The Joint Board for the West Region

May 12, 2006

Executive Summary:
Recommendations of the Federal/State
Joint Board on Economic Dispatch for the West Region

On September 10, 2005, the Federal Energy Regulatory Commission (the Commission) issued its Order Convening Joint Boards Pursuant to Section 223 of the Federal Power Act "to study the issue of security constrained economic dispatch for the various market regions," "to consider issues relevant to what constitutes 'security constrained economic dispatch' and how such a mode of operating . . . affects or enhances the reliability and affordability of service," and "to make recommendations to the Commission."[1]

The West Joint Board consists of the Federal Energy Regulatory Commission and the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Texas, Utah, Washington and Wyoming.[2]

Our analysis of security constrained economic dispatch (SCED) began with the Commission's definition in the Order: "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities." In the Report, we discuss the basics of SCED and how it functions in the Western Interconnection. Below are short summaries of the major issues considered by the Board and our recommendations to the Commission in this Report.[3] We also address three recommendations made to the Joint Boards by the DOE in The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005.

1. Independence of dispatcher.

The Board examined the suggestion that independent transmission dispatch was needed to ensure fairness and the full integration of the all generation facilities into the dispatch without regard to ownership of those facilities.

Recommendation:
We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is deemed

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[1] The Order was issued in Docket No. AD05-13-000, Joint Boards on Security Constrained Economic Dispatch.

[2] These states are within the Western Interconnection,with the exceptions of South Dakota and Texas, only portions of which are served from within the interconnection.

[3] Texas's recommendations diverge from the majority, and are contained in the *Texas Perspective on Security Constrained Economic Dispatch*, filed separately in Docket No. AD05-13-000.

warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

2. Utility dispatch of third party power through contracts.

The Board examined the question of whether the relationship between dispatching utilities and IPPs should be governed by contract to ensure the high level of reliability and responsiveness needed for the dependable dispatch of contract units as fully functional integrated grid resources.

Recommendation:

We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing reliability, dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with an LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

3. Transparency of dispatch information and processes.

The Board examined the question of whether a central entity, dispatching all of the resources in a region, that had more timely access to high quality information could function more efficiently and better realize the value of SCED. For competitive reasons, some entities are reticent about sharing confidential dispatch and load information with a non-independent dispatching entity.

Recommendation:

Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

4. Consolidation of control areas in a region.

The Board looked at the question of whether consolidation of control areas might yield better information which might, in turn, enable more efficient dispatch than would be the case if several control areas simply shared information. The benefits of larger control areas for renewable technologies such as wind were discussed as was the range of information available from WECC and otherwise to smaller control areas.

Recommendation:

We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

5. Import/export schedule changes within an hour.

The Board learned that large changes in load and large amounts of imported power make it difficult to schedule efficiently for the hour in some markets. Slow ramp rates can cause imbalances when scheduling for the hour.

Recommendation:

We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the hour.

6. Some practical limitations on economic dispatch.

The Board recognizes that the physical makeup of the grid, the demands placed on it and the available generation resources sometimes impose cost, reliability and other limitations on economic dispatch to assure that the needs of the public are accommodated. Various state and regional policies also emphasize goals that go beyond "pure" economic dispatch.

Recommendation:

We recommend that the definition of security constrained economic dispatch be flexible and broadened to include other public policies, values and physical and operational constraints as well as costs.

7. First DOE Recommendation: review dispatch practices.

The DOE recommends that the Joint Boards review selected dispatching entities to determine how they conduct economic dispatch and document the rationale for deviations from "pure" least-cost economic dispatch.

Recommendation:

The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing

much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

8. Second DOE Recommendation: standardize dispatch contract terms.

The DOE recommends that it and FERC encourage stakeholders to develop more standard contract terms concerning price stability, dispatchability, reliability, and penalties for not meeting performance standards.

Recommendation:
We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

9. Third DOE Recommendation: review dispatch tools.

Existing economic dispatch technology, including software and data used and the underlying algorithms and assumptions, deserve scrutiny.

Recommendation:
We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.

I. Introduction

This Report of the West Joint Board on Economic Dispatch presents the results of the Joint Board's study of security constrained economic dispatch (SCED) issues, and provides recommendations to the FERC. The West Joint Board is one of four joint boards designated by the Commission under EPAct2005, Section 1298, Economic Dispatch. The members of the West Joint Board are:

Commissioner Suedeen Kelly, Federal Energy Regulatory Commission, Chair of the West Joint Board
Commissioner Marsha H. Smith, Idaho Public Utilities Commission, Vice Chair of the West Joint Board
Commissioner Marc L. Spitzer, Arizona Corporation Commission
Commissioner Dian M. Grueneich, California Public Utilities Commission
Chairman Gregory Sopkin, Colorado Public Utilities Commission
Commissioner Thomas J. Schneider, Montana Public Service Commission
Mr. Richard L. Hinckley, General Counsel, Public Utilities Commission of Nevada
Commissioner E. Shirley Baca, New Mexico Public Regulation Commission
Chairman Lee Beyer, Oregon Public Utility Commission
Commissioner Dustin Johnson, South Dakota Public Utilities Commission
Commissioner Barry Smitherman, Public Utility Commission of Texas
Chairman Ric Campbell, Utah Public Service Commission
Chairman Mark Sidran, Washington Utilities and Transportation Commission
Deputy Chair Kathleen A. "Cindy" Lewis, Wyoming Public Service Commission

The West Joint Board met in public session on November 13, 2005 in Indian Wells, California and on February 13, 2006 in Washington, D.C.

As the Commission noted in the initial order convening the joint boards:

> Each joint board is authorized: (1)"to consider issues relevant to what constitutes 'security constrained economic dispatch'"; (2) to consider "how such a mode of operating an electric energy system affects or enhances the reliability and affordability of service to customers in the region concerned"; and (3) "to make recommendations to the Commission regarding such issues."

This report contains four sections in addition to this introduction: Section II provides a description of the basic concept of SCED used in the study; Section III provides background on the variations in dispatch procedures in the west; and Section IV gives a summary of the issues raised and considered by the Joint Board, together with recommendations to address these issues. The principal source material for this Report include [i] presentations to the Joint Board, [ii] written comments submitted to the Joint

Board, [iii] discussions among the Joint Board members at Board meetings and otherwise, [iv] the DOE report under EPAct 2005, Section 1234[4], and [v] the responses to the DOE survey of economic dispatch under Section 1234.

II. Security Constrained Economic Dispatch: the Basics

For purposes of the joint boards' studies, the FERC adopted the following definition of security constrained economic dispatch:

> "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."[5]

This definition describes the basic way all utilities in the region endeavor to dispatch their own and purchased resources to meet electricity load. The basics of SCED are described in this section to establish a common understanding of the process before addressing issues and recommendations.

There are a number of unique challenges to supplying electricity: production must occur simultaneously with demand; demand varies greatly over the course of a day, week, and seasons; the costs of generation from different units and different types of units vary greatly; and scheduled and unplanned outages in a generator fleet and expected and unexpected conditions on the transmission network affect which generation units can be used to serve load reliably. SCED is an optimization process that takes account of these factors in selecting the generating units to dispatch to deliver a reliable supply of electricity at the lowest cost possible under given conditions.

The economic dispatch process occurs in two stages, or time periods: day-ahead unit commitment (planning for tomorrow's dispatch) and unit dispatch (dispatching the system in real time).

In the *unit commitment* stage, operators must decide which generating units should be committed to be on-line for each hour, typically for the next 24-hour period (hence the term "day ahead"), based on the load forecast. In selecting the most economic generators to commit, operators must take into account each unit's physical operating

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[4] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005.

[5] September 30, 2005, Order at ¶14.

characteristics, such as how quickly output can be changed, maximum and minimum output levels, and minimum time a generator must run once it is started. Operators must also take into account generating unit cost factors, such as fuel and non-fuel operating costs and costs of environmental compliance.

Operators must also consider other factors that may affect what resources should be included in the next day dispatch, such as required environmental limits on annual unit output, and non-power uses of hydro resources. These factors can affect the eventual cost of utilizing the resource, but cannot be easily translated into daily or hourly production costs.

In addition, conditions that can affect the transmission grid must also be taken into account to ensure that the optimal dispatch can meet load reliably. This is the "security" aspect of the commitment analysis. Factors that can affect grid capabilities include generation and transmission facility outages, transmission path congestion (line capacities as affected by loading levels and flow direction), inadvertent loop flow and the weather. If the security analysis indicates that the optimal economic dispatch cannot be carried out reliably, relatively expensive but better situated generators may have to replace cheaper units.[6] Operators might perform the unit commitment analysis a few times during the day before actually committing generators for the next day dispatch.

In the *unit dispatch* stage, operators must decide in real time the level at which each available resource (from the unit commitment stage) should be operated, given the actual load and grid conditions, such that overall production costs are minimized while the necessary level of service is maintained. Actual conditions will vary from those forecasted in the day-ahead commitment and operators must adjust the dispatch accordingly. As part of real time operations, demand, generation, and interchange (imports and exports) must be kept in balance to maintain a system frequency of 60 Hz (per NERC standards). This is usually done by using Automatic Generation Control (AGC) to change the generation dispatch as needed. In addition, transmission flows must be monitored to ensure that they stay within reliability limits and voltage stays within reliability ranges. If transmission flows exceed accepted ranges, the operator must take corrective action, which could involve curtailing schedules, changing the dispatch, or shedding load. Operators may check conditions and issue adjusted unit dispatch instructions as often as every five minutes. The Western Electricity Coordinating Council (WECC) provides reliability related service throughout the Western Interconnection and closely monitors the condition of the network.

[6] This is known as "out of merit" dispatch.

III. Economic Dispatch in the West

The practice of economic dispatch in the West varies by area. For purposes of this report, we will organize the discussion around the four areas used by WECC. These subregions[7] are shown in Figure 1 and are as follows:

- Northwest Power Pool Area (Northwest)
- California-Mexico Power Area (California)
- Arizona-New Mexico-Southern Nevada Power Area (Southwest)
- Rocky Mountain Power Area (Rockies)

The overall pattern of dispatch in the West depends to a large extent on differences between the resources and loads in each area. The Northwest has an abundance of hydropower and a load that peaks during the winter, while the Southwest has a load that peaks during the summer. As a result, a historical pattern of flows has developed where power in the summer flows from available hydropower in the north to peak loads in the south, while power in the winter flow from south to north to meet the peak loads in the northwest. The north-south transmission system has developed to support this pattern, and provides for overall economic utilization of generation resources when water conditions permit. In a similar way, the main fuel sources for thermal power generation, coal and natural gas, tend to be in the Rockies or to the east in Texas and Oklahoma, while the major population centers are to the west, in California and the Pacific Northwest. The electric transmission systems reflect the need to move power west from coal generation; this movement of power is less seasonal than the north-south movement, as much of the power comes from baseload plants that run year round.

The CAISO is the one multi-utility area market in the west that is centrally organized and dispatched. The remainder of the areas in the west perform economic dispatch on a cooperative but decentralized basis, with a form of control area or utility dispatch similar to the basic dispatch described in the previous section. However, there is considerable variation in individual practices in each area that distinguish the way economic dispatch is practiced. The variations in regional practice are discussed briefly below.

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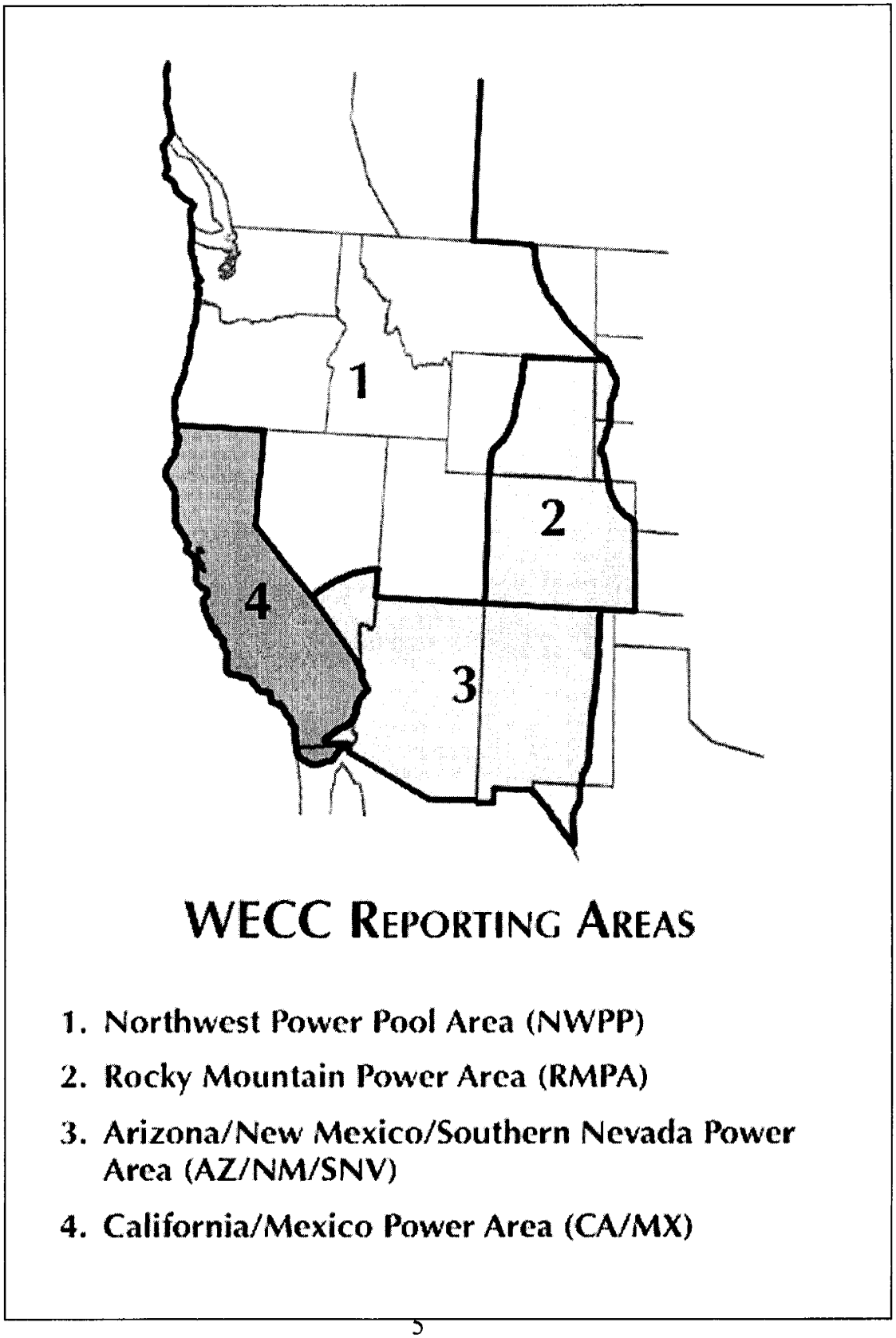
[7] Because the Western Interconnection is coextensive with the area being studied by the West Joint Board, Commissioner Smith recommended using the term "subregion" when referring to less than the entire Western Interconnection region. Transcript of February 13, 2006, meeting of West Joint Board, hereinafter Tr. 2, pp. 49-50.

Figure 1. Western Regions for Economic Dispatch Discussion



A. Northwest

Although significant hydropower resources exist throughout the west, they dominate power generation in the Northwest. Fifty eight percent of capacity in the Northwest is conventional hydropower; seventy nine percent of the total western hydropower resources occur in the Northwest.[8] In the west as a whole, hydropower accounts for thirty four percent of the total capacity.[9] This level of hydropower resources alters the way economic dispatch is performed in the Northwest and in the entire west, making western dispatch issues significantly different from those in the Eastern Interconnection and ERCOT.

Several characteristics of hydropower have direct implications for dispatch in the Northwest:

- Economic dispatch needs to consider the overall optimization of hydropower and thermal resources, making the problem of resource optimization much more difficult than it is in a power system based exclusively or primarily on thermal resource capacity.
- Hydropower generation resources in the Northwest are highly interdependent, so that they need to be dispatched as a coordinated system for power generation, rather than as separate, independent power sources.
- Conventional hydropower is generally limited by the total available energy stored in the water behind the dams, not by the total generating capacity of the resource.
- Hydropower can generally be dispatched very quickly when available, providing an abundance of low cost, rapidly dispatchable capacity to an extent not present in the other North American interconnections.

These characteristics have led to a long history of coordination in the Northwest, beginning around 40 years ago with the Columbia River Treaty with Canada and the Pacific Northwest Coordination Agreement (PNCA), and including the Mid-Columbia Hourly Coordination Agreement (MCHA). The PNCA enables both Federal and Non-Federal projects to operate as a single utility owner to optimize power and nonpower river demands, while the MCHA optimizes the hydraulic operation of seven dams on the Columbia River. The MCHA permits hydropower resources to provide load following for much of the Northwest load, and hydropower resources also provide regulation and reserves at a low cost.

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[8] WECC, 2005 Information Summary, Total Existing and Planned Generation, p. 6.

[9] *Id.*

Another factor affecting Northwest dispatch is operation of BPA's transmission assets, which are closely connected to the operation of hydropower resources. Historically, the coordinated operation of the system of dams meant that all power was treated equally regardless of location on the system, so that a megawatt had the same value at any location. Until relatively recently, there were few constraints on the BPA transmission system, so there was sufficient transmission capacity to ensure that coordination would work successfully. In the last few years, there have been an increasing number of internal constraints; and BPA is now moving toward a power flow based methodology to more accurately capture transmission effects in dispatch.[10]

The coordination of power and non-power uses leads to determining the optimum power operation *within* the non-power constraints. This optimum operation is distinct from the objective of minimizing short term operating costs. The valuation of hydropower resources for short term dispatch presents unique challenges when such a high percentage of resource is low cost in the short term and potentially high (and uncertain) in value over the longer term.

Although the presence of hydropower in the Northwest significantly affects the overall operation and dispatch of the power system, the basic dispatch remains decentralized and economic dispatch is conducted on a utility by utility basis rather than being coordinated centrally. Plans for the development of a RTO in the Northwest are not being actively considered; but Columbia Grid has recently begun efforts to form a grid organization in the Pacific Northwest.

Based on the responses to the DOE survey and the utility presentations at the initial meeting of the West Joint Board, utility dispatch in the Northwest is similar to the basic model described in the Section II, once operations are adjusted for the presence and limitations of hydropower. The main difference is less emphasis on day-ahead unit commitment of thermal resources to provide load following and reserves, because hydropower is generally the lowest cost alternative for these functions and will be used when available. Utilities report dispatching a mix of their own generation, independent generation committed under contract, and wholesale spot market purchases, combined to achieve the lowest cost from the resources available. These dispatch decisions are generally made before the operating day, either in the day ahead planning or earlier, and take into account factors other than strict operating costs, such as environmental limits, fuel contract terms, opportunity cost of company-owned hydropower, and similar factors.

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[10] BPA, Economic Dispatch in the Pacific Northwest, presentation to the meeting of the West Joint Board for the Study of Economic Dispatch, Palm Springs, CA, November 13, 2005. (FERC Docket No. AD05-13-000)

Although planning for dispatch may take into account a wider range of sources, hourly or real time adjustments are often restricted to company owned resources or resources under contract that permit the utility sufficient flexibility in the terms of the dispatch.

B. California

The California ISO (CAISO) performs an economic dispatch covering most of California, with the exception of some control areas.[11] Formed in 1998, the CAISO dispatches a single control area, corresponding to the former control areas of California's three largest Investor Owned Utilities. Prior to the formation of the CAISO, each of the three control areas performed single utility economic dispatch, by dispatching their own resources and other resources under their control. This dispatch was similar to the basic dispatch process described in Section II, using the costs of the generation resources to establish the order of the dispatch and running the lowest cost resources available, given the security constraints of the system.

The CAISO consolidated the dispatch of the three utilities into a single dispatch for approximately 45,000 MW of California peak load, by balancing generation and load every 10 minutes based on market bids from generation resources. This balancing market was similar to the previous control area balancing function in that lower cost generation resources were dispatched before higher cost resources; however, the traditional utility costs were replaced by bids to the CAISO. This change altered the economic dispatch process in two fundamental ways: [i] all resources capable of being dispatched were eligible to submit bids on an equal basis, and [ii] the market bids that replaced the utility production cost estimates were no longer required to be tied to actual production costs of the utility.

In October 2004, the CAISO began the Real Time Market Application (RTMA), a new market application that plans a 5 minute dispatch for 2 hours in the future, dispatches online resources on a 5 minute basis in real time, and starts "fast start" resources on a 15 minute interval. A Market Redesign and Technology Upgrade (MRTU), planned for late 2007, will include the use of market bidding for day ahead planning and unit commitment, and greater detail in representation of the transmission grid for more accurate representation of the security constraints in the economic dispatch decision. These changes will enhance the dispatch processes of the CAISO, but will not change the basic differences between the CAISO dispatch and dispatch in the rest of the west: CAISO will continue to perform the only centralized, multiple-utility, market-bid-based

[11] Examples of control areas inside California, but not included in the CAISO dispatch are the Los Angeles Department of Water and Power in Southern California, Sacramento Municipal Utility District in Northern California, and a few others throughout the state.

economic dispatch in the west. Although the CAISO is the only area in the West with this type of dispatch, its operation has significant effects on dispatch in the rest of the west because the total load in California is large (approximately thirty percent of the summer peak load for the west)[12] and California relies on significant imports from the rest of the west. Because California is so closely dependent on imports from the rest of the west, and because long distance power transactions are an important factor in overall power flow, the centralized dispatch in the CAISO has greater direct impact on other areas in the WECC than comparably-sized centralized dispatch in the Eastern Interconnection has on other areas in the east.

The CAISO dispatch includes all resources needed to serve the load, both those that can be dispatched on a 5-minute basis and those that are not capable of responding to 5-minute dispatch signals. The non-dispatchable resources include generating plants that must be run for longer time periods, such as nuclear plants, as well as imports into the CAISO control area. These imports follow scheduling procedures set for the WECC as a whole, and must conform to fixed hourly schedules for exchanging power between control areas. Although imports are eligible to bid into the CAISO market for dispatch in real time, they must do so on an hourly basis and cannot be varied in the real time dispatch.

The CAISO is still evaluating the current implementation of real time dispatch, the RTMA, but notes two changes from the previous economic dispatch.[13] First, prices have become more volatile and the fluctuation of the dispatch has increased. This result is consistent with the change in the design of the dispatch, which was intended to promote more frequent balancing of generation and load and produce market prices that more closely mirrored that balance. Second, RTMA has improved the handling of "start up" problems, including improved pricing of import/export bids. Coordination of the balance of hourly exports/imports and 5-minute generation dispatch continues to be a challenge, however, particularly when load is rapidly fluctuating.

C. Southwest and the Rockies

Although the Southwest and Rockies are separate areas, they have a single reliability coordinator, located at the WECC Rocky Mountain/Desert Southwest Reliability Center (RDRC) in Colorado. Both areas rely principally on thermal resources, but face somewhat different issues in performing economic dispatch. The Southwest has a larger amount of hydropower capacity in the generation mix, and has a significantly greater

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[12] Based on a summer peak load of 141,100 in 2004, *WECC, 2005 Information Summary*, p. 2.

[13] *Assessment of Economic Dispatch Practices at the CAISO*, initial Meeting of the West Joint Board on Economic Dispatch, November 13, 2005, p. 18.

level of trade with California.

Natural gas is the largest single source of generation in the Southwest, followed by coal and nuclear. Hydropower also plays a significant role, with slightly over ten percent of the total area capacity. Dispatch throughout the area is by individual utilities that perform unit commitment and economic dispatch of the own resources, supplemented by resources controlled by contract and purchases from the spot market. Generally, the large base load plants are located near fuel sources that are remote, and in some cases hundreds of miles away from the load centers. These base load units may be jointly owned, each with its own dedicated capacity that needs to be dispatched. Consequently, the availability of transmission facilities is a factor that must be taken into account in the economic dispatch. This general pattern of utility dispatch is followed by large investor owned utilities such as Arizona Public Service, large projects such as the Salt River Project, and smaller cooperatives and public power entities. Thus the Southwest dispatch is similar to the basic model described in the Section II, and does not have the extensive procedures needed to coordinate the dispatch of the hydropower resources of the Northwest, nor has it adopted the centralized dispatch procedures used in the CAISO. Active spot markets exist at the Palo Verde, Four Corners and Mead hubs, providing a basis for price discovery in the Southwest and points of reference for including wholesale purchases in the economic dispatch.[14]

El Paso Electric (EPE), the only Texas electric provider in the Western Interconnection, is a small part of that grid, and is in a particularly constrained area to the extent that, in the short run, moving to a broader regional dispatch may have little impact for EPE. However, Texas believes there are longer-term regional and national benefits that could be obtained from a more coordinated dispatch through more efficient fuel use and the development of the competitive wholesale electricity market in the western region.[15]

Like the Southwest, the Rockies generation resources are largely thermal, with coal being the largest generation resource, followed by natural gas, and dispatch follows the single utility approach, together with use of resources under contract and spot market purchases. The utilities serving this area utilize WECC's services in coordinating and promoting electric system reliability on the Western Interconnection. WECC supports efficient competitive power markets, open and non-discriminatory transmission access among members (including, e.g., BPA, CAISO, LADWP, and many privately and cooperatively held utilities serving throughout the West), provides a forum for resolving transmission access disputes, and fosters coordination of the operating and planning activities of its members.

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[14] *See,* DOE survey comments of APS, Salt River Project and Arizona Electric Power Cooperative on the use of wholesale spot purchases in the dispatch.

[15] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

D. Western Systems Power Pool

Trading between utilities and between sub-regions of the West improves the dispatch of resources. Such trade is enhanced by the Western Systems Power Pool (WSPP). As discussed above, there is a long history in the West of both seasonal (north-south) and resources-to-load (east-west) power movement. For these reasons, there has been an active wholesale electricity market in the West for decades. This market became more formalized in 1987, when FERC approved the WSPP. The WSPP has provided a platform for short-term transactions throughout the Western Interconnection for economy energy, unit commitment, and firm sales or exchange services. With over 220 WSPP members (virtually all market participants), the WSPP agreements are the most widely used standardized power sales contracts in the electric industry.

As a result, this readily available platform for day-ahead and real-time transactions adds an important dimension to SCED in the West. (Even entities within the CAISO, many of which are WSPP members, can use the WSPP agreements to import power if the transmission capability exists.) It allows Western electricity market participants to use risk management strategies more effectively in order to meet their load service obligations at the lowest cost practicable and in a reliable manner. These wholesale activities provide enhanced operational flexibility, particularly when water available for hydroelectric generation is subnormal, unplanned generation or transmission outages occur or transmission constraints exist. They also provide economic flexibility based on how wholesale prices compare with marginal generation costs. Thus, the ability to trade electricity on a West-wide basis greatly influences the process of economic dispatch.

This has led to the development of numerous robust wholesale trading hubs in the Western Interconnection, such as Mid-Columbia, Palo Verde, California-Oregon Border, North Path 15, and South Path 15, where numerous wholesale electricity purchases and sales occur on a daily basis. Sales volumes and prices at these hubs are reported on a voluntary basis to ICE (IntercontinentalExchange Inc.), Dow Jones, and other reporting services, aggregated by hub, and made public daily. Sales by jurisdictional utilities are also reported to FERC in Electronic Quarterly Reports.

IV. Issues and Recommendations

This section describes the issues considered by the Joint Board, and identifies any recommended approaches for addressing these issues..

The Joint Board makes two general observations regarding any approach to issues relating to SCED. First, Joint Board members generally believed that there should not be a "one size fits all" approach to the use of SCED. Differences among the areas in the west, and often differences within each area, are too large to warrant recommending a

single form of SCED for all areas or utilities. Second, the focus of changes from current practices should be at the state or local level. Regional or subregional changes should be based on collaborative efforts among utilities, other market participants and states, rather than on legislative or regulatory initiatives at the federal level.

Recommendations from the DOE report to Congress on the value of economic dispatch are discussed at the end of this section.

A. Observations

Introduction

A number of general issues have been raised about the nature of economic dispatch, its scope and uses, and implications for affordable and reliable service to electricity consumers. These general issues include:

- Relative importance of hourly dispatch costs
- Least cost production may not be lowest cost for the ratepayer
- The broad choice between cost-based and bid-based dispatch

Relative importance of economic dispatch.

Some board members and market participants expressed the desire to put the implications of economic dispatch in an overall cost perspective. In terms of total overall cost, economic dispatch, when framed in terms of daily and hourly dispatch, was felt to be relatively unimportant compared to long term investment in generation and transmission.[16]

Least cost production may not be lowest cost for the ratepayer.[17]

This issue was raised by several board members, in reference to environmental costs, the nonpower issues of hydropower scheduling, and other considerations. The concern was that many factors are considered in the unit dispatch decision that cannot be easily translated into short term monetary terms, so that exclusive emphasis on minimizing daily or hourly production costs could prove to be more expensive to the ratepayer in the long run.

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[16] Commissioner Schneider,Transcript of first West Joint Board meeting (Tr.) at 116.

[17] Commissioner Beyer, Tr. at 114.

Choice of cost based or bid based dispatch.

This issue focused on the idea that economic dispatch often arose in the context of choice between two different systems of dispatch. The cost-based system referred to the basic single utility dispatch where a utility dispatched its own units based on its own generation costs and other factors, and was compared to a system with a separate grid operator that dispatched generation resources based on bids to supply power and then set a market price for the power based on the bids. Each overall approach gave rise to different sets of specific issues regarding the factors to consider for SCED. One board member noted the existence of these different approaches, and proposed that the board not recommend a single approach to this issue.[18]

B. Specific Dispatch Issues

Introduction

The specific dispatch issues raised varied by subregion, with different issues raised in each of the areas of the west, and by market segment within regions, and with different issues raised by utilities, independent power producers, grid operators and state regulators. These specific issues are listed below and discussed in the remainder of this section.

- Independence of dispatcher
- Utility dispatch of third party power through contracts
- Transparency of dispatch information and processes
- Consolidation of control areas
- Regional scope benefits
- Import/export schedule changes within an hour

Independence of dispatcher.

A representative from the independent power producers (IPPs) recommended that some type of independent transmission dispatch was needed so that independent power producer resources could be fully integrated in the hour-to-hour operation of the dispatch.[19] In discussion, the IPP representative stated that dispatcher independence was

[18] Commissioner Campbell, Tr. at 110

[19] Mr. Kahn, Tr. at 91.

a prerequisite for merit order dispatch.[20]

Board discussion:

There are three dispatch models employed in the Western Interconnection: [i] the California Independent System Operator (CAISO), [ii] individual utilities performing economic dispatch within their control areas, and [iii] public and private utilities cooperating to dispatch the Northwest's multi-owner hydroelectric system.[21] All three models may be assisted by the WSPP. Faced with a variety of different operating scenarios and the issues they raise, including those concerned with the performance of independent operators, states should be allowed to deal with these issues themselves. Texas states that "having an independent grid coordinator with access to comprehensive regional information can significantly enhance reliability and market operations."[22] However, there is little enthusiasm among other Joint Board Members for creating new independent dispatchers where the current system is functioning properly; and "joining or not joining a regional dispatch entity should be up to each utility and the negotiation with their regulatory body."[23] Decisions on dispatcher independence should be flexible and responsive to the needs of the state [24] Independent entities should not be created for their own sake:

> Where utilities perform dispatch functions and do so fairly and efficiently, they should not be supplanted with an independent dispatcher simply for the sake of having one. Utilities operating in such a manner should be involved with the development of independent dispatching entities.[25]

In addition to a general caution regarding significant changes to existing dispatch practices, two recommendations were put forward: (1) keep any structural changes flexible and sensitive to the needs of the states; and (2) make changes voluntary wherever possible.[26] Several board members cited this issue in their summary remarks.[27] In addressing the question, regulators should remember that both public and private entities serve load in many areas. All have duties to serve the public but all do not have the same

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[20] Mr. Kahn, in response to a question from Commissioner Grueneich concerning whether a utility would always favor its own generation, Tr. at 94.

[21] Commissioner Campbell, Tr. 2, p. 38; and Commissioner Smith, Tr. 2., p. 38.

[22] *Texas Perspective on Security Constrained Economic Dispatch*, p2.

[23] Mr. Brown, Tr. 2., p37.

[24] Commissioner Sidran, Mr. Brown and Commissioner Grueneich, Tr. 2, pp. 36-39.

[25] *Wyoming Discussion Points*, February 3, 2006, p. 1.

[26] Ms. Edwards, Tr. at 73.

[27] Commissioner Greuneich, Tr. at 111; Commissioner Beyer, Tr. at 115.

level or type of regulatory oversight.[28]

Recommendation:
We recommend that independent dispatch entities not be created for their own sake. We do not recommend further analysis at this time. If any further analysis is later deemed warranted, it must include an investigation of the potential benefit to consumers. If further work appears justified on the facts, the affected states and relevant utilities should determine the nature of the dispatching entity to be considered. Where public, cooperative and privately owned entities serve the market under consideration, their participation should be encouraged.

Utility dispatch of third party power through contracts.

This issue was cited by both utilities and non-utilities, with utilities sometimes arguing that it was difficult to obtain sufficient performance and reliability from third party contracts. One utility stated the primary difficulty with incorporating non-utility generation in their dispatch was their "inability to complete alternative actions in a swift and economic manner."[29] Independent power producers stated the opposite position, arguing that their generation was flexible and capable of being very responsive, but that they were often denied the ability to dispatch power by utility generation owners who controlled the dispatch, particularly in the case of hourly dispatch and ancillary services.[30]

Board discussion:
This issue describes the ongoing tension among IPPs and incumbent utilities on the subject of IPP integration; and the independent producers should play a constructive and full role in the development of a system capable of accommodating them. IPP integration should be approached as part of a cooperative effort, overseen on a subregional level by appropriate entities or on an interconnection-wide level by WECC through its committee process. Entities should carefully consider the potential reliability and dispatchability impact of the IPP on the Western Interconnection or relevant portions thereof and should make sure that the IPP bears its fair share of the costs of integration with the system, including the up-front cost of creating any independent dispatch capability to accommodate their participation. Thus, consideration of "merit order" dispatch should be done in the context of an overall cooperative effort and not as a goal in and of itself. The ultimate end of the effort is to serve the consumers better and more efficiently, and consideration of when to dispatch will likely have less monetary impact on consumers

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[28] Commissioner Sidran, Tr. 2, p. 40.
[29] Portland General Electric response to DOE survey, p. 2.
[30] Mr. Kahn, Tr. at 88.

than will wise choices of what resources to build.[31]

Further progress will require basic contract commitments by IPPs regarding dispatchability and other issues. EPSA and EEI proposals to develop standard contract terms should be encouraged.[32] In summary, Commissioner Kelly cited the following member's observation as the consensus of the Joint Board that it should:

"Encourage contractual commitments by independent producers to provide energy in a manner consistent with the utility's dispatch, but do not require utilities to purchase nonutility power."[33]

Recommendation:
We encourage, but do not wish to duplicate, the efforts of EPSA and EEI in developing standard contractual language addressing dispatchability and other issues. The Joint Board recommends the use of contractual commitments by IPPs to provide capacity, energy and ancillary services in a manner consistent with the relevant LSE's dispatch needs. Integrating IPPs into the dispatch in the Western Interconnection should be overseen by WECC on an interconnection-wide basis, or subregionally by an appropriate entity.

Transparency of dispatch information and processes.

One of the benefits cited for an independent entity dispatching all resources in a region was the ability to provide a transparent process for the dispatch. One utility representative argued that full value economic dispatch would not be fully realized without this transparency.[34] Without the independence condition, sharing sensitive real-time information between a utility transmission provider and third parties can be viewed as an impediment to dispatching economically. [35]

Board discussion:
Transparency of information and process can enhance the dispatch function, but the desire to promote transparency should not drive the decision as to whether or not an independent dispatch entity is needed. Transparency is not an end in itself. It can further some of the goals of economic dispatch, but should not serve as a rationale for creating

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[31] See, *Wyoming Discussion Points*, February 3, 2006, pp. 2-4.

[32] See discussion of the Second DOE Recommendation in section C of this document.

[33] Tr. 2, p. 41; and Attachment C to Supplemental Notice of Second West Joint Board Meeting in FERC Docket No. AD05-13-000, p. 1.

[34] Mr. Larson, Tr. at 49.

[35] Discussion between Commissioner Smith and Mr. Larson, Tr. at 53 and 54.

an independent entity to achieve transparency. Furthermore, one board member observed that too much market knowledge can potentially foster collusion which can do damage to the market ostensibly being helped.[36] Transparency of information can be a benefit to a region, but that benefit is not in itself sufficient to support a mandate for regional economic dispatch.[37]

In a related observation, the Department of Energy suggested that there should be further study of the "impact of the accuracy of load forecasting and quality load forecasting on the results of economic dispatch." If the quality of forecasted information is low, the resulting dispatch may be wasteful. DOE suggested the study look at the costs of suboptimal forecasting and "ways to improve the quality of forecasting to improve economic dispatch."[38]

Recommendation:
Achieving transparency is not sufficient by itself to justify the creation of an independent dispatch entity. We recommend that the Department of Energy study ways to improve the accuracy of forecasting to improve economic dispatch and identify savings that could be achieved thereby.

Consolidation of control areas in a region.

The current single-utility dispatch means that each utility first determines a dispatch for its own area with only limited knowledge of conditions in other areas. In the Western Interconnection, WECC provides important real time information on the status of the grid which assists dispatchers. However, coordination among control areas may sometimes be based on limited information on generation availability in other areas and constraints on transmission available for imports and exports between control areas, when compared to the information available within each control area. The larger the number of areas, the greater the potential benefit of consolidating control areas, in principle, arising from better information available to the dispatchers and better control over generation and transmission resources. Some presenters recommended that control areas be consolidated, citing the large number in an area like the Northwest.[39] Others argued that there were potential benefits to SCED from consolidation, without taking a position on whether the benefits of consolidation would exceed the costs.[40] Texas cited the ERCOT example of combining ten control areas into one as providing evidence of significant

[36] Commissioner Schneider, Tr. 2, p. 44.
[37] Commissioner Sidran, Tr. 2, p. 42.
[38] Ms. Silverstein, Tr. 2, p. 62.
[39] Mr. Kahn, Tr. at 89.
[40] BPA in comments submitted in the docket.

benefits from control area consolidation and regional dispatch.[41]

Board discussion

Consolidation of control areas should be approached rationally rather than making consolidation an aim in itself. Single utilities do not dispatch in an informational vacuum, but frequently are in contact with relevant control centers and entities throughout the Western Interconnection. Very large control areas encounter problems in dealing with 15-minute import/export exchange to ameliorate problems of scheduling on the hour. However, it is also true that larger control areas can be a positive development if the integration of smaller control areas makes operational sense. This is especially true for wind resources which can benefit from being part of larger and hence more diverse control areas. The focus should be on the technological advisability of consolidation and not on simply reaching the goal of larger and larger control areas.[42] The geography of the West has already helped to create relatively large control areas, which is not always the case in other parts of the nation. We therefore must be careful to examine the costs and usefulness of further consolidation.[43] WECC's three reliability centers which can see the entire Western Interconnection should be an integral part of the analysis of control centers. WECC is now studying its reliability centers to determine both the number of centers needed in the future and what tools are required to see the whole of the Western Interconnection at once and to issue reliability directives. Commissioner Smith cautioned against creating new single-generator control areas.[44]

Increasing the size of the dispatch region, even without consolidating regions into a single control area, can lead, in principle, to a lower cost dispatch through inclusion of more generation and transmission resources. However, there appeared to be no consensus on whether such regional benefits exist in practice. Some cited regional benefit studies that concluded there were positive net benefits; for example, the representative from the Independent Power Producers cited a recent study for Grid West as demonstrating benefits.[45] One utility representative stated that there were potential benefits from regionalization, without citing a specific study. However, at least some board members felt the current system of utility dispatch coupled with spot and short term market purchases worked efficiently. One board member cited the adage, "If it ain't broke, don't fix it."[46]

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[41] *Texas Perspective on Security Constrained Economic Dispatch*, p1.

[42] Commissioner Campbell, Tr. 2, pp. 45-46; and his comment approving *Wyoming Discussion Points*, February 3, 2006, p. 3.

[43] Commissioners King and Johnson, Tr. 2, pp. 47.

[44] Commissioner Smith, Tr. 2, pp. 47-49.

[45] Mr. Kahn, Tr. at 90.

[46] Commissioner Baca, Tr. at 119.

The west should carefully examine the usefulness of creating larger dispatch regions on an individual basis. Participation by major stakeholders should be assured before meaningful consolidation can take place. The west should draw on the well developed grid management experience of institutions such as WECC, and on the wholesale market facilitation and coordination experience of entities such as WSPP, to assist in deciding whether or not to form larger dispatch -- or control -- areas. Case-by-case examination would better fit with the diversity encountered in the Western Interconnection than would a blanket consolidation mandate.[47]

Recommendation:

We recommend that the states, individually or jointly, consider further consolidation of control areas. Further studies should take into account [i] the value of larger control areas for renewables such as wind, and [ii] solving the problems of large control areas in scheduling within the hour. Any consolidation decision should be based on the needs of consumers and the region's economy for reliable and affordable power; and we recommend that consolidation not be thought of as a goal in itself. Enlargements should be approached on a case-by-case basis with the assistance of WECC and possibly the WSPP.

Import/export schedule changes within an hour.

The CAISO identified large hourly schedule changes as a problem for their dispatch. The source of this problem is that schedules between control areas change at the beginning of each hour and remain constant for the hour. Because the CAISO often has large amounts of imported power at the same time that it has large changes in load over the hour, it becomes difficult to accommodate these large blocks of hourly imports while following a volatile load.[48] To address this issue, CAISO recommended spreading the changes out over the hour to decrease the magnitude of each change.[49] Scheduling could still occur on an hourly basis, but each hourly schedule could increase or decrease on a less than one hour basis, for example, on 15 minute intervals. Because scheduling imports and exports between control areas in the west follows a standard protocol, developing the ability to provide schedule varying on 15 minute intervals would require coordinated development of such a change throughout the west.[50] One board member cited this recommendation positively, but there was no further comment from other board members at the initial meeting.[51]

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[47] Commissioner Lewis, Tr. 2, p. 50.
[48] Mr. Rothleder, Tr. at 38.
[49] Mr. Rothleder, Tr. at 41.
[50] Mr. Rothleder, Tr. at 39.
[51] Commissioner Campbell, Tr. at 110.

Board discussion:
Although this is, at this time, a situation most focused on California and the CAISO as it confronts loads which are more volatile than imports over the hour, the Board in general supported the concept.[52] Oregon's experience shows that hourly scheduling of interchanges between utilities is complicated by relatively slow ramp rates which can cause utilities to experience imbalances. Allowing for ramp rate changes, e.g., 10 minutes before and after the hour, could significantly reduce these imbalances. The Board accepted this addition as an important consideration for further work on the topic.[53]

Recommendation:
We recommend that the WECC develop a standard west-wide protocol to address the need for scheduling before, during and after the top of the hour.

Some practical limitations on economic dispatch.

The heavy and increasing reliance on natural gas as a generator fuel must be included in future studies of economic dispatch. Recognizing that it is subject to substantial price volatility, the ideal might be to dispatch the most efficient natural gas plants to make the best possible use of our natural gas resources. The study of the challenges inherent in the use of natural gas may begin with the distinction between economic dispatch and efficient dispatch. The United States Department of Energy has described the differences between these concepts:

> In a recent hearing of the Senate Energy and Natural Resources Committee*, there was great interest in determining whether economic dispatch practices could or should be modified to ensure the most efficient use of scarce natural gas in gas-fired generation units. "Economic dispatch," as noted above, is an optimization process crafted to meet electricity demand at the lowest cost, given the operational constraints of the generation fleet and the transmission system. Although economic dispatch will *usually* run higher efficiency gas-fired units before lower efficiency units, that is not always the case, for a number of possible reasons. "Efficient dispatch" would presumably seek to modify the practice of economic dispatch to ensure that more efficient gas-fired units are *always* used before less efficient units.
>
> Despite DOE's interest in ensuring the efficient use of natural gas for electricity generation and other purposes, it remains skeptical of the merits of "efficient dispatch," for several reasons:

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[52] Commissioners Grueneich and Kelly, Tr. 2, pp. 51-52.
[53] Mr. Brown and Commissioner Kelly, Tr. 2, pp. 52-53

- The fundamental purpose of economic dispatch is to reduce consumers' electricity costs. "Efficient dispatch" would take the dispatch process off this path and increase consumers electricity costs – for benefits that may not be large enough to offset these additional costs.
- Economic dispatch is at best a complex process, and modifications to it must be made with care in order to minimize unanticipated consequences. Modifying it to achieve short-term non-economic policy objectives should be considered only as a last resort.
- A better alternative would be to examine the practice of economic dispatch itself to determine whether modifications are needed to better achieve its traditional objectives – which could by itself lead to more efficient use of natural gas. A review of this kind could be pursued through the regional joint FERC-State boards created by EPAct in Sec. 1298.[54]

* Senate Committee on Energy and Natural Resources, Full Committee Hearing – Hurricane Recovery Efforts, October 27, 2005

Board discussion:
SCED is defined above in Section II of this report sufficiently broadly to include more localized reliability concerns. Therefore, the definition of SCED should not later be so narrowly construed that it makes it impractical or too costly to incorporate such local reliability and other considerations in regional, subregional or state analyses.

California observed, as a practical matter, that it would probably have to keep older and less efficient natural gas-fired plants in operation to deal with more localized issues of reliability and system congestion. This goes to the heart of how we define economic dispatch in the future and means that there must be practical rather than only theoretical assessments of system capabilities and costs. Commissioner Grueneich of California observed that, to accommodate these considerations, either [i] the definition of economic dispatch should be broadened to take such reliability-related issues into account, or [ii] the inquiry should be taken beyond economic dispatch to allow these issues to be considered.

Similarly, California recommends incorporation of renewable generation in the economic dispatch process. In California, economic dispatch also means incorporating the State's policy of encouraging the development of renewable energy sources and the preferred resource loading order. California's "Energy Action Plan II" includes a loading order that identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs followed by renewable generation, combined heat and

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[54] *The Value of Economic Dispatch: A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 11. Text of report found at http://www.electricity.doe.gov/document/value.pdf

power and distributed generation, and traditional fossil resources. Some other states across the country have also adopted renewable portfolio standards in many ways similar to California's but with different regional goals which reflect public policy in those individual states.[55]

Even with overall goals of trying to address natural gas prices and of implementing direct economic dispatch, the local cost and reliability issues will vary to such an extent that each particular situation should be examined closely -- "on a very decentralized basis."[56]

Better service to the people is the primary goal of this inquiry. Issues of reliability and system congestion can have region-wide implications, but they also have a strong local dimension which can keep purely theoretical economic dispatch from being the best or most realistic solution. The best way to deal with such challenges is to make analyses on a case-by-case basis, not ignoring economic dispatch but recognizing that it is not an end in itself and that it should not be promoted with disregard for its local effects.

Recommendation:
We recommend that the definition of security constrained economic dispatch be broadened to include other public policies, values and physical and operational constraints as well as costs.

C. Recommendations from the DOE Report to Congress

The DOE Report to Congress, *The Value of Economic Dispatch*, contains three recommendations that are relevant to the security constrained economic dispatch issues that the Joint Board has been considering. These three recommendations are described below.

First DOE Recommendation: review dispatch practices

FERC-State Joint Boards should consider conducting in-depth reviews of selected dispatch entities, including some IOUs, to determine how they conduct Economic Dispatch.[57] These reviews could document the rationale for all deviations from pure least cost, merit-order dispatch, in terms of procurement, unit commitment and real-time dispatch. The reviews should distinguish entity-specific and regional business practices

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[55] Commissioner Grueneich, Tr. 2, pp. 11-13.

[56] Commissioner Grueneich, Tr. 2, pp. 57-58.

[57] *The Value of Economic Dispatch, A Report to Congress Pursuant to Section 1234 of the Energy Policy Act of 2005*, United States Department of Energy, November 7, 2005, p. 52.

from regulatory, environmental and reliability-driven constraints. These reviews could assist FERC and the states in rethinking existing rules or crafting new rules and procedures to allow IPPs and other resources to compete effectively and serve load.

Board discussion:

The study recommended here was generally seen as being at odds with the general consensus of the Joint Board that economic dispatch has to be a flexible concept, capable of adapting to the varying needs of different states and subregions in the Western Interconnection. The study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. [58] On the other hand, California, with its substantial unregulated municipal utility presence, could benefit from a better understanding of how these entities make economic dispatch decisions, although jurisdictional and funding issues probably make the issue unripe at this time.[59] The new rules presupposed in this recommendation may be incorrectly assumed necessary. The recommendation is also at odds with the complexity of economic dispatch issues in the Western Interconnection.[60] The Joint Board generally agreed that this recommendation should not be pursued. However, Texas believes that there are potentially significant benefits from SCED that warrant study and disagrees with the recommendation not to pursue further study at this time.[61]

Recommendation:

The Board recommends that this study not be pursued. Such a study would take us deeply into variables and deviations from "pure" economic dispatch without providing much value. It is at odds with our fundamental conclusion that economic dispatch must remain a flexible concept.

Second DOE Recommendation: standardize dispatch contract terms

FERC and DOE should explore EPSA and EEI proposals for more standard contract terms and encourage stakeholders to undertake these efforts.[62] Specifically, the EEI has proposed that [i] IPPs should commit to provide energy at specified prices for specified times to meet unit commitment schedules, and [ii] there should be contractual performance standards with penalties for failure to deliver. EPSA proposed developing technical protocols for placing and accepting supply offers, operational requirements, non-performance penalties, and standard contract forms for routine transactions.

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[58] Commissioner Sidran, Tr. 2, pp. 23-24.

[59] Commissioner Grueneich, Tr. 2, pp. 24-25.

[60] Commissioner Smith, Tr. 2, pp. 25-26; Commissioner Schneider, Tr. 2, p. 26.

[61] Commissioner Smitherman, Tr. at 126-28.

[62] *DOE Report* at p. 51.

Board discussion:

A high level of cooperation already exists in the electric industry and among the non-utility generators regarding contracts.[63]Existing initiatives should be the vehicle for crafting standard language of the kind envisioned in the Recommendation and therefore it should be pursued by industry and the IPPs rather than through duplication by the Joint Board or the federal government. The Recommendation rightly recognizes the value of communication among stakeholders to refine their relationships. The Joint Board recognizes the valuable and ongoing work of the North American Energy Standards Board (NAESB) to promote well crafted standardized contracts to encourage efficiency in the electric and natural gas marketplaces.[64] We also encourage EPSA and EEI to go forward with standard contract language proposals. We believe that these existing initiatives should be monitored and encouraged but not duplicated.[65] Regional differences in some cases may be so pronounced that standard contracts should take them into account. Thus, a Western Interconnection contract might of necessity differ from one employed in the East. We note the difference between on-peak products in the East and the West.[66] Wyoming's comment on this subject summarizes the Joint Board's response to this recommendation: [67]

> We think this recommendation should be pursued on a regional basis rather than on a national basis. The regional variances in grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis. This does not mean that standardized terms are per se are a bad idea or that federal resources such as those of the DOE should not play an important collaborative role.

Recommendation:

We recommend that the standardization of dispatch contract terms be pursued on a regional basis rather than on a national basis. The regional variances in transmission grid operating parameters throughout the Western Interconnection make a strong case for allowing development to go forward on a regional basis.

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[63] Mr. Hinckley, Tr. 2, p. 28.

[64] Commissioner Sidran, Tr. 2, p.32

[65] Commissioner Smith, Tr. 2, pp. 31-32.

[66] Commissioner Campbell, Tr. 2, p. 31; and New Mexico Comments of February 13, 2006, p. 3.

[67] Commissioner Lewis, Tr. 2, pp. 28-29; and Commissioner Campbell, Tr. 2, p. 31; and *Wyoming Discussion Points*, February 3, 2006, p. 4.

Third DOE Recommendation: review dispatch tools

Current economic dispatch technology tools deserve scrutiny.[68] These tools include software and data used to implement economic dispatch, as well as the underlying algorithms and assumptions.

Recommendation:
We recommend the development and refinement of technological tools to make the best use of existing and proposed facilities.[69]

[68] DOE Report at p. 53.
[69] Commissioners Smith, Grueneich, and Mr. Hinckley, Tr. 2, pp. 33-34.

Attachment E

Case 21090 Blumenstock Direct

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED DIRECT TESTIMONY

OF

RICHARD T. BLUMENSTOCK

ON BEHALF OF

CONSUMERS ENERGY COMPANY

~~June~~ October 2021

Q. Please state your name and business address.

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

Q. By whom are you employed?

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

Q. What is your position with Consumers Energy?

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

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

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

Q. What is your formal education experience?

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

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

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

- Case No. U-16045-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2010;
- Case No. U-16432-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2011;
- Case No. U-16890: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2012;
- Case No. U-16890-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2012;
- Case No. U-17429: Approval of a Certificate of Necessity ("CON") for the Thetford Generating Plant pursuant to MCL 460.6s and for related accounting and ratemaking authorizations;
- Case No. U-17317: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2014;
- Case No. U-17317-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2014;
- Case No. U-17752: Authority to amend its renewable energy plan ("REP") approved in Case Nos. U-15805, U-16543, U-16581, and U-17301;
- Case No. U-17678: Approval of a PSCR Plan and for Authorization of Monthly PSCR Factors for the Year 2015;
- Case No. U-17678-R: Reconciliation of PSCR Costs and Revenues for the Calendar Year 2015;
- Case No. U-18250: Application of Consumers Energy for a financing order approving the securitization of qualified costs and related approvals associated with the early termination of the Palisades Nuclear Energy Plant ("Palisades") Power Purchase Agreement ("PPA");

- Case No. U-20134: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief;
- Case No. U-20165: Application of Consumers Energy for approval of its Integrated Resource Plan ("IRP") pursuant to MCL 460.6t and for other relief;
- Case No. U-20697: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief; and
- Case No. U-20963: Application of Consumers Energy for authority to increase its rates for the generation and distribution of electricity and for other relief.

Q. What is the purpose of your direct testimony?

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

Q. Are you sponsoring exhibits with your direct testimony?

A. Yes, I am sponsoring the following exhibits:

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

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

A. Yes.

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

A. In June 2019, the Commission approved a settlement agreement which resolved the Company's 2018 IRP and resulted in the approval of a PCA which represented the best plan for Michigan at that time. That PCA became the foundation of the Company's Clean

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

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

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

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

These requests are designed to provide: (i) $~~640~~ 628 million cumulative customer savings; (ii) long-term electric supply reliability, which is expected to be 90 times greater than otherwise achieved through the Company's currently approved IRP; (iii) a 50% reduction in energy market reliance which mitigates customer cost exposure to market volatility; (iv) continued expansion of demand-side and renewable resources at a pace to reach and give further opportunity to transform to a cleaner resource mix; (v) financial stability of the regulated electric utility; and (vi) immediate planet benefits by eliminating 63 million tons of carbon, reducing emissions of criteria pollutants such as sulfur dioxide ("SO_2"), nitrogen oxides ("NO_x"), mercury, and particulate matter, eliminate use of 220 billion gallons of fresh river and lake water, and eliminate 3 billion cubic yards of ash waste;

2) Accounting approvals related to the accelerated plant retirements. Specifically, the Company is proposing: (i) regulatory asset treatment to recover the remaining net book balances of Campbell Units 1, 2, and 3 and Karn Units 3 and 4 through their current design lives; (ii) approval to defer employee retention costs; and (iii) approval to make retirement transition costs a regulatory asset. The requested approval for the recovery of the remaining net book balances is necessary because the Company would be required to record an impairment for some portion of the above identified Campbell and Karn units if the Commission does not authorize a method of recovering the remaining net book balances of the plants, which includes the full recovery of financing costs, at the same time the PCA is approved. Approval of regulatory asset treatment for expenses associated with community transition plans for the Karn site and the Campbell site and regulatory asset treatment for expenses associated with the Campbell retention and separation plan is necessary because these expenses have not been previously approved by the Commission and capturing these expenses in a regulatory asset will allow for future review and recovery of these costs if they are deemed to be prudent;

3) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises Company ("CMS Enterprises"). The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct rules. The competitive solicitation also complied with the Federal Energy Regulatory Commission's ("FERC") standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. In the alternative, while complying with all other provisions of the Code of Conduct, the Company requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Kalamazoo, and Livingston plants from CMS Enterprises;

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

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

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

7) In addition to the requested approval of the acquisition and purchase costs of the Covert, DIG, Kalamazoo, and Livingston plants, as described above, and the proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP as reasonable and prudent for cost recovery purposes pursuant to MCL 460.6t. The total costs that the Company is seeking approval of include:

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

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

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

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

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

The Company's PCA embodies a truly balanced plan across People, Planet and Prosperity. It offers continued growth of clean renewable resources at or better than the levels identified in the approved 2018 IRP; greater electric supply reliability; greater customer savings realized in the short and mid-term years of the plan; near-term planet benefits due to reduction in carbon emissions, other air emissions, water, and waste; and

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

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

SECTION I: IRP OVERVIEW

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

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

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

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

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

Q. Please explain the Company's 2018 IRP.

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

- The approval of the Company's PCA as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons and a refresh of the evaluation is to be provided by the Company in a new IRP filing made by June 2021 to continue to show the plan is the most reasonable and prudent means of meeting the Company's energy and capacity needs;

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

- The accelerated retirement of Karn Units 1 and 2 in 2023 and to seek recovery of the unrecovered book balance by no later than May 31, 2023;

- A Company-conducted retirement analysis of Campbell Units 1 and 2 which will be presented in the Company's 2021 IRP;

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

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

- Approval of an FCM on PPAs approved by the Commission on or after January 1, 2019, including PURPA contracts;
- Continued collaboration with the local transmission owners, Michigan Electric Transmission Company ("METC") and ITC Holdings ("ITC"), and with MISO; and,
- Various analysis and modeling requirements (i.e. stochastic risk assessment).

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

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

- ~4,500 MW of solar by the year 2030 and over 6,000 MW by 2040;
- ~2,000 MW peak load reduction from customer efficiency programs (EWR, DR, and CVR);
- 450 MW of batteries by the year 2040;
- accelerated retirement of Karn Units 1 and 2 from May 31, 2031 to May 31, 2023;
- an assumed extension of the MCV contract from 2025 to 2030;
- Palisades PPA termination and site closure in 2022;
- Campbell Units 1 and 2 operating to May 31, 2031 and Campbell Unit 3 operating to December 31, 2039; and
- Karn Units 3 and 4 operating to May 31, 2031.

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

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

- The completion of the 2019 Solar Request for Proposal ("RFP") for 300 MWs planned to be operational in 2022. The Commission approved the 140 MW Calhoun PPA, the 150 MW Mustang Mile Build Transfer Agreement ("BTA"),

and an open offering of 10 MW to PURPA Qualifying Facilities ("QFs") at the Commission-approved full avoided cost rate set by the Mustang Mile BTA. See Case No. U-20165, April 8, 2021 and May 26, 2021 Orders;

- The issuance of the 2020 Solar RFP for 300 MW planned to be operational in 2023. Contract negotiations are in progress;
- The development of the 2021 Solar RFP for 500 MW planned to be operation in 2024;
- The method for recovery of the FCM was established in the Company's 2020 electric rate case, Case No. U-20697;
- The Commission approved an amendment to extend the term of the Palisades PPA until May 31, 2022, which provides customers capacity from Palisades for the entire 2021/2022 MISO Planning Year, in an August 20, 2020 Order Approving Settlement Agreement in Case No. U-20734;
- The Commission approved an amendment to extend the MCV PPA from 2025 to 2030 in a March 4, 2021 Order in Case No. U-20896;
- The Company has acquired the customers to account for 461 MW of DR for MISO Planning Year 2021;
- The Company has achieved 1.6% savings equivalent to 1.8% savings in 2020 and is on track to meet or exceed the 2% 2021 savings target projected in the Company's currently approved IRP;
- The Company has achieved 5.7 MW and 5,643 MWh of CVR within projected costs for 2020; and
- The Company has contracted with, and is bringing online, 519 MW of 525 MW of wind and 100 MW of solar by end of 2021 as planned in the REP.

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

Q. Why has the Company filed this IRP?

A. As discussed above, as part of the settlement agreement approved in Case No. U-20165, the Company's 2018 IRP, the parties agreed that the Company would file its next IRP in

June 2021. This filing represents a "refresh" of the Company's approved 2018 IRP and is intended to ensure that the Company's approved IRP continues to represent the most reasonable and prudent plan to meet the Company's energy and capacity needs.

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

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

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

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

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

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

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

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

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

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

Company remains committed to the higher standard of reducing all sources of generation to serve its customers to reach Net Zero Carbon Emissions by 2040. The Company's PCA, as proposed in this IRP, puts the Company on track to exceed the Paris Climate Agreement scenarios and the Governor's MI Healthy Climate targets. The Company's PCA also puts the Company in the position to have many options to choose from over the next 20 years to achieve its commitment to the planet. This is further discussed by Company witness Heather A. Breining.

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

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

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

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

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

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

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

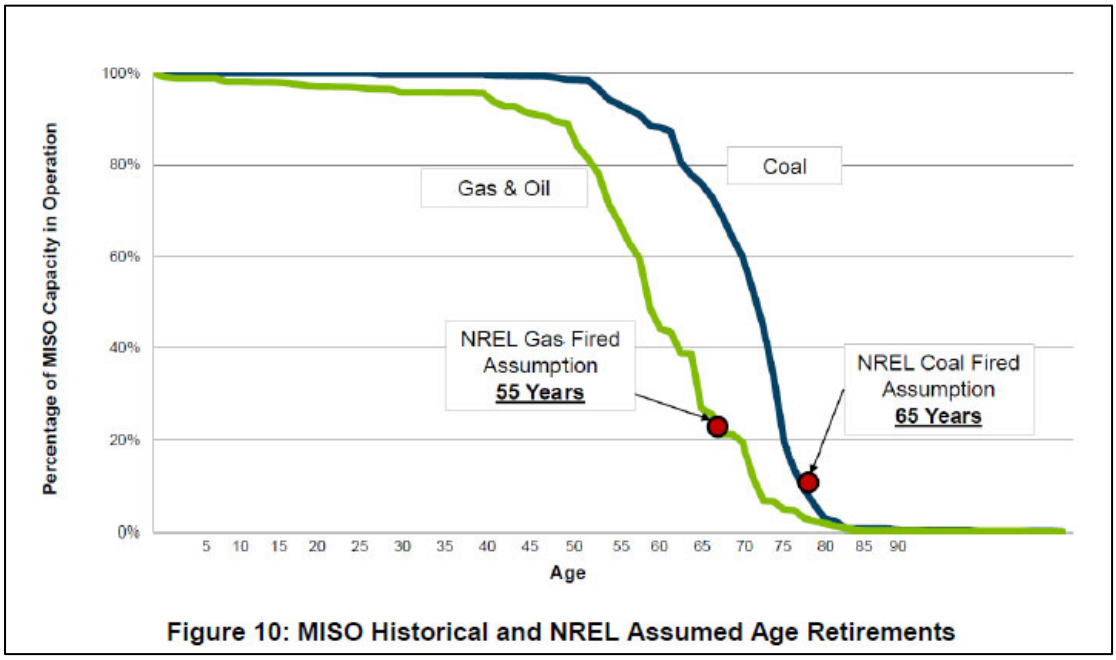
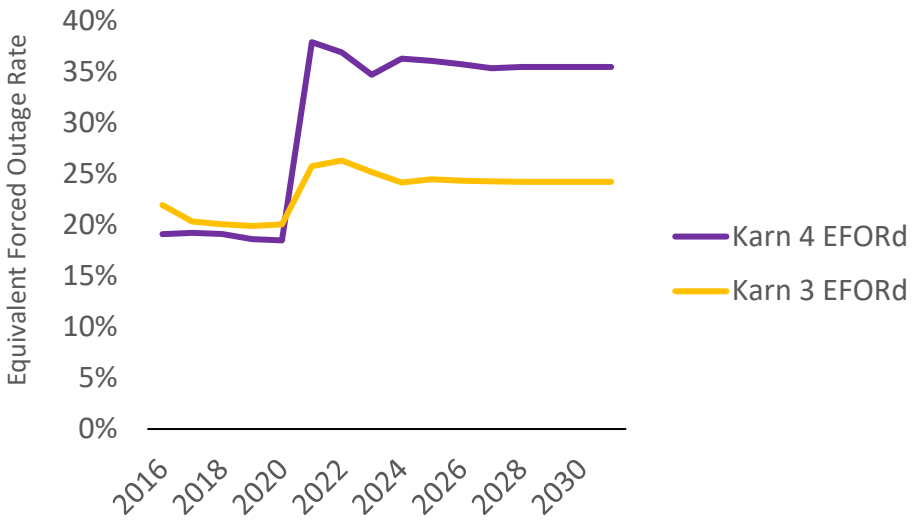


Figure 10: MISO Historical and NREL Assumed Age Retirements

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

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

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



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

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

A. Yes. This filing meets the requirements set forth by the Commission in Case No. U-18418 (Michigan IRP Modeling Parameters), Case No. U-15896, et al (Michigan IRP Filing Requirements), and Case No. U-20633 (Emissions Reporting). The Company's filing also meets the requirements in Section 6t of Act 341. Exhibit A-1 (RTB-1) details each IRP

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SECTION II: IRP OBJECTIVES AND PRINCIPLES

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

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

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

ii. Compliance with applicable state and federal environmental regulations;

iii. Competitive pricing;

iv. Reliability;

v. Commodity price risks;

vi. Diversity of generation supply; and

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

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

People

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

Electric supply reliability is central to the Company's *People* commitment. Providing enough capacity to serve anticipated peak electric load plus applicable PRMR and LCR results in reliable energy supply (Commission objectives i and iv) and preparing

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

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

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

Planet

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

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

Prosperity

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

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

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

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

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

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

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

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

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

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

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

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

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

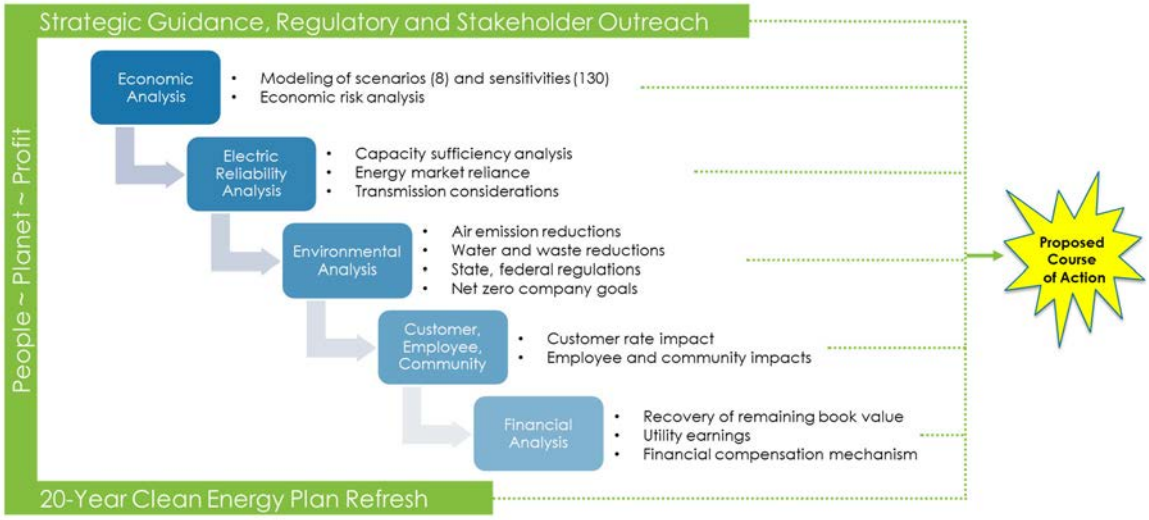
interests allows customers to access potentially lower cost supply alternatives while providing a fair return. This approach is reasonable and compliant with Act 341, Section 6t.

SECTION III: IRP PROCESS

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

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

Figure 3: Integrated Resource Plan Process and Key Analysis



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

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

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

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

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

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

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

2018 IRP. The paragraph 13, item (m.), of the settlement agreement specifically required the Company to include:

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

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

The Company evaluated the level of energy and capacity market reliance of the resource plan. For capacity market reliance, the LOLE Study is used to understand the number of consecutive hours, days, and amount of the market purchases for capacity in the year 2032, the first year of full operations of the generating fleet with reduced controllable fossil generation, under varying conditions. A resource plan relying fully on the CIL or market of 3,200 MW in consecutive hours and days over a majority of the year indicates

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

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

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

A. The Company evaluates environmental benefits of a resource plan by assessing impacts to air emissions, water usage, waste creation and/or elimination, and land impacts due to new resource builds or potential for re-purposing. The air emissions evaluated by the Company include carbon emissions from a 2005 baseline, NO_x, SO_2, particulate matter, and mercury. The water usage/savings are based upon annual gallons used for cooling systems of thermal units. The creation or reduction of waste is based upon annual coal ash production. Land use is a qualitative measure of the ability to redevelop or repurpose coal asset site locations

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

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

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

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

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

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

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

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

Q. Please describe the public outreach efforts.

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

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

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

Q. Please describe the technical workshops.

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

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

2) Stakeholders to ask the Company clarifying questions; and

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

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

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

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

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

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

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

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

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

development of the PCA. Company witness Scott describes in more detail the collaboration efforts with METC/ITC.

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

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

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

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

A. Once the above analysis was complete, the results were reviewed from the perspective of reasonableness in assumptions and alignment with principles and objectives. The resulting portfolio of resources became the PCA. The PCA was evaluated through all scenarios and sensitivities to understand its performance under all study conditions and was measured

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

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

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

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

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

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

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

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

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

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

portfolio optimization analysis. The scenarios, sensitivities, assumptions, and modeling approach are discussed in detail in the direct testimony of Company witness Walz.

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

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

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

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

Q. Please describe how the PCA was developed.

A. The PCA was developed as a refresh to the currently approved IRP and the results of modeling and analysis as described above in Figure 3. The Company identified the demand-side management and supply resources most widely selected by the Company's Aurora software across the scenarios and sensitivities. Based upon the resource plan generated by the BAU identifying natural gas units as an economic selection for customers

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

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

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

positioned to collaborate with the many departments and work necessary to create the best plans to serve Michigan's electric needs.

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

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

SECTION IV: IRP BASELINE CAPACITY POSITION

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

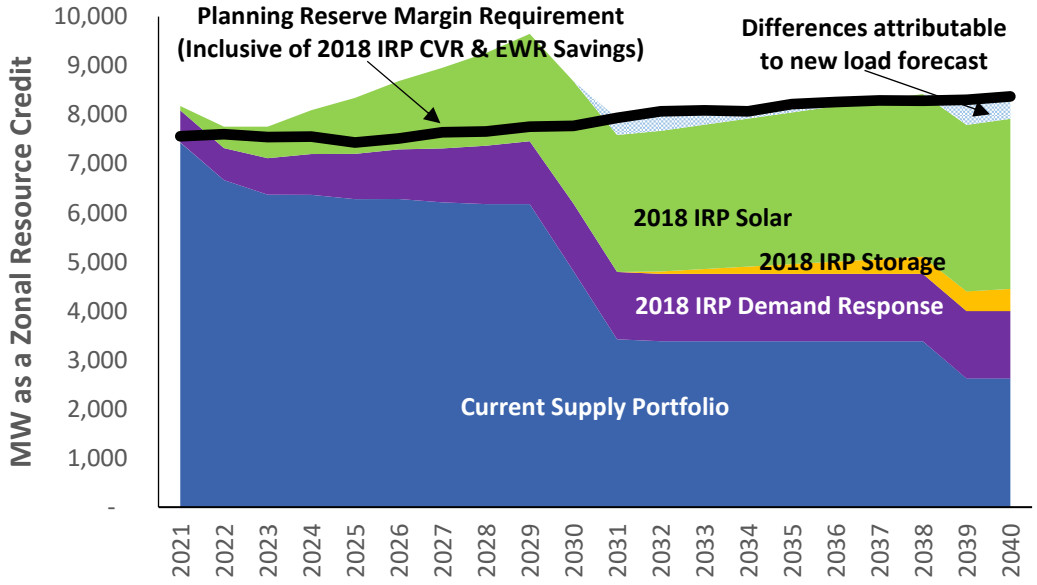
A. The Company meets the capacity and energy needs of its customers pursuant to its currently approved IRP, as described above. The Company's approved IRP provides energy and capacity through a diverse mix of demand and supply-side resources.

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

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

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

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



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

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

A. The base capacity positions were developed for each scenario evaluated in the IRP. The base capacity position outlooks start from a spring of 2020 forecast of electric demand.

The capacity position is defined as the total amount of planning resources in ZRCs less the total load forecast plus PRMR. The Company created four base capacity positions. A base capacity position was developed for the Company scenarios used for retirement analysis ("CE"), the MPSC required scenarios ("Annual Energy Outlook" or "AEO"), the Company's Advanced Technologies scenario, and the MPSC-required Carbon Reduction scenario. The base capacity positions are further described in the direct testimony of Company witness Walz.

Q. Why were different base capacity positions created?

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

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

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

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

- DR at levels pre-approved in Case No. U-20165 for the period June 2020 through June 2022, as detailed in the direct testimony of Company witness McGraw. 2019 levels were also approved in the Company's 2018 electric rate

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

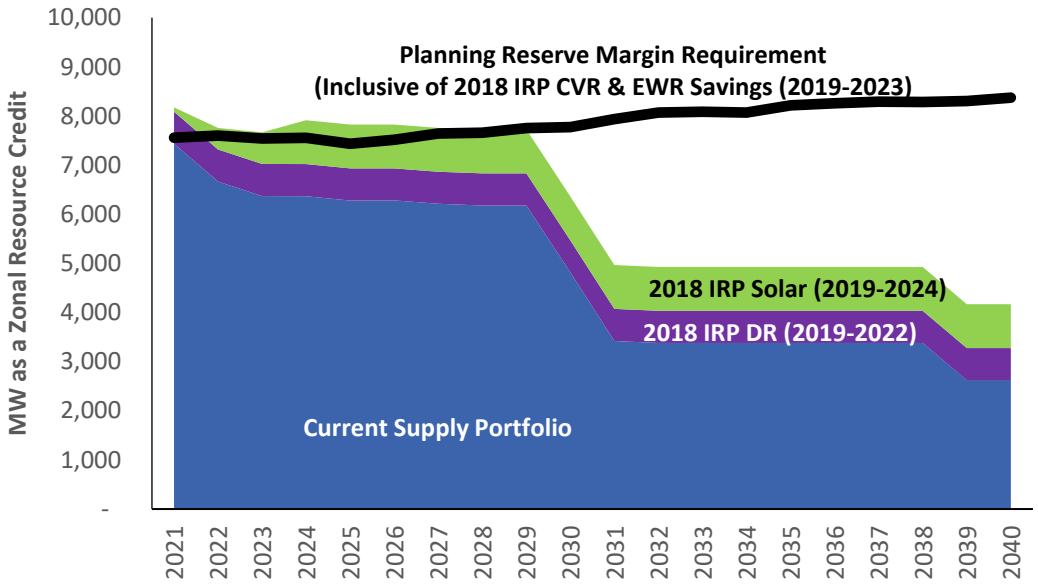
- EWR at levels pre-approved in Case No. U-20165 for the period June 2019 through June 2023, consistent with the Company's Biennial EWR plan Case No. U-20372, as detailed in the direct testimony of Company witness McLean. Planned EWR incremental to these levels were removed in years 2024 through 2040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

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

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

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

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



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

- Operation of Karn Units 1 and 2 through May 31, 2023;
- Operation of Karn Units 3 and 4 through their design lives (May 31, 2031);
- Operation of Campbell Units 1 and 2 through their design lives (May 31, 2031);
- Operation of Campbell Unit 3 through its design life (December 31, 2039);
- Zeeland and Jackson plants extend their design lives beyond 2040;
- 856 MW (139 ZRCs) of wind generation made operational as of 2021 as part of the Company's REP (Case No. U-18231);
- 100 MW (50 ZRCs) of contracted solar generation to be operational in 2021 as part of the Company's REP (Case No. U-18231);
- PPA with MCV continues to May 31, 2030; and
- PPA with Palisades to be terminated on May 31, 2022.

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

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

SECTION V: PROPOSED COURSE OF ACTION

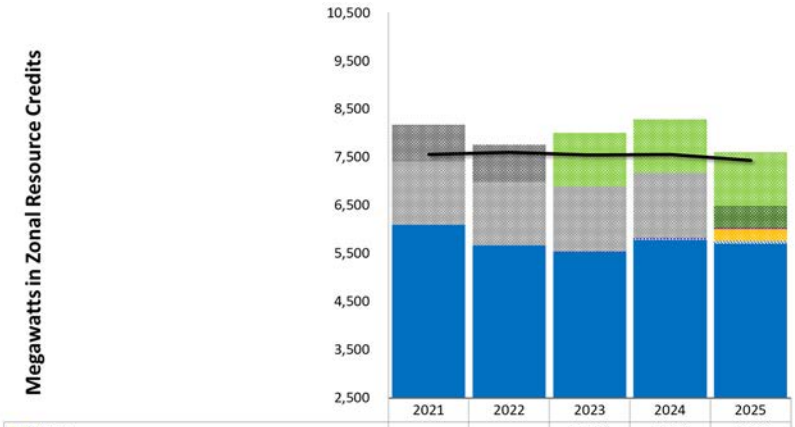
Q. Please describe the components of the Company's PCA.

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

Q. Please provide an overview five-year plan.

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

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



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

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

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

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

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

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

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

A. As indicated above, the Company proposes to purchase the Covert Plant in 2023. The Covert Plant is a combined cycle natural gas-fired electric generating plant commissioned in 2004 with a nameplate capacity of 1,176 MW which is located in Covert, Michigan. The Covert Plant is currently operating in Michigan as a market participant in the PJM regional transmission organization. However, the Covert Plant originally operated in the MISO regional transmission organization. The transmission facilities needed to allow operation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. As set forth in Figure 1, the National Renewable Energy Laboratory's assumption for the life of a gas-fired unit is 55 years. However, as explained below in description of the 20-year plan, for simplicity in capacity expansion modeling, the Company is showing an assumed cease of operations of the Covert, DIG, Kalamazoo, and Livingston plants by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets.

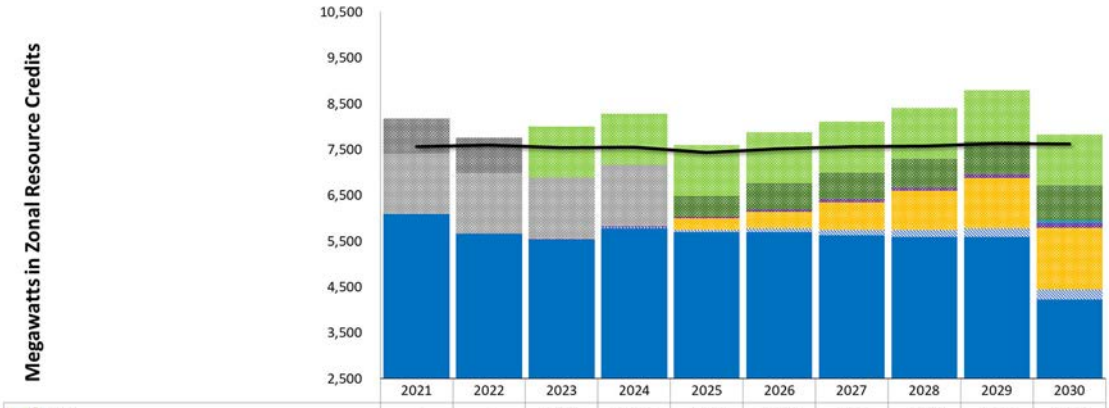
Q. Does the Company anticipate any potential socioeconomic impacts, such as employment, for the local regions of the to-be-purchased existing gas resources?

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

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

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

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



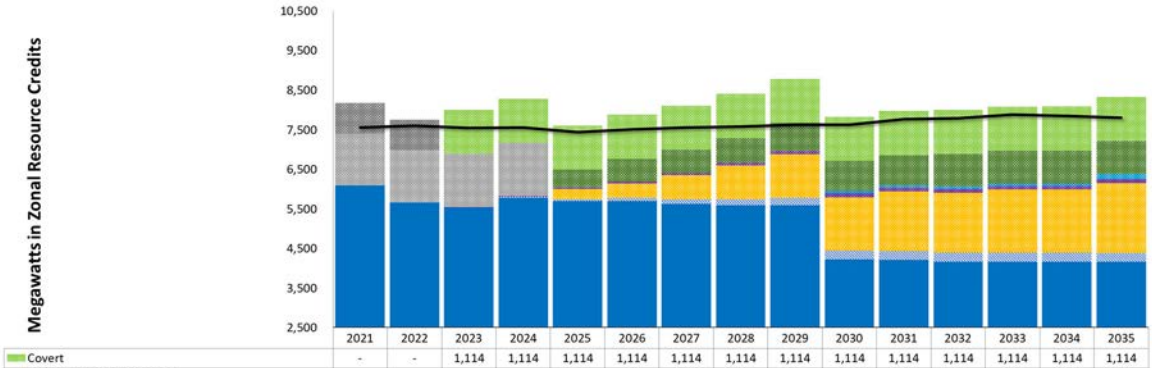
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Covert	-	-	1,114	1,114	1,114	1,114	1,114	1,114	1,114	1,114
DIG, Kalamazoo, Livingston	-	-	-	-	451	579	579	619	711	767
Karn 3&4	767	769	-	-	-	-	-	-	-	-
Campbell 1-3	1,313	1,318	1,344	1,346	-	-	-	-	-	-
New storage	-	-	-	-						55
New Demand Response	-	-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

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

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

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

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



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

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

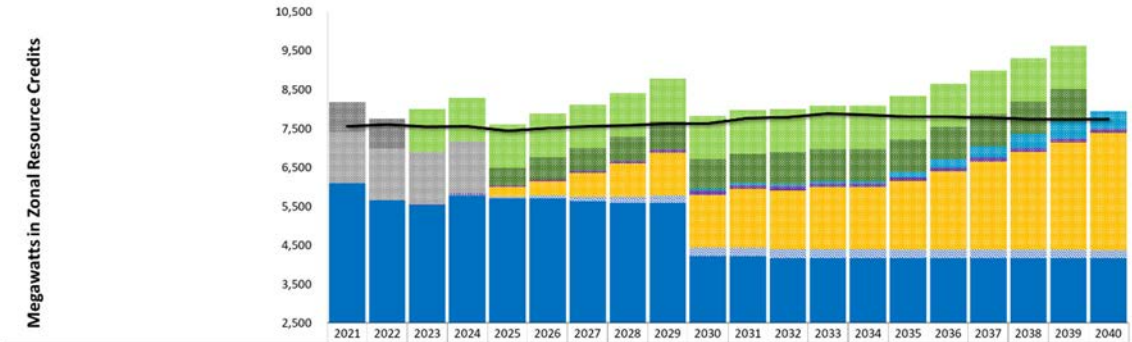
- Solar
  - 2031 to 2035 – reaches 3,518 MW (1,759 ZRCs) by 2035 increasing the total solar to 5,302 MW (2,651 ZRCs); and
- Storage:
  - 2031 to 2035 – reaches (145 MW) 138 ZRCs of batteries by 2035. These batteries represent the additions of a distribution asset upgrade deferral battery and traditional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

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

A. The 20-year plan is a continuation of the 15-year plan with an expansion of energy efficiency savings over 2% per year (2.1% in year 2040), solar, and batteries. Starting in 2035, the Company begins its second glidepath of solar reaching 6,018 MW (3,009 ZRCs) by 2040 and a glidepath of batteries reaching of 475 MW (450 ZRCs) by 2040. The expansion of solar and batteries, and the continued commitment to the levels of demand-side management programs, are the replacement technologies for the assumed retirement of 2,000 ZRCs of existing gas units. For simplicity in capacity expansion modeling, the Company is showing an assumed cease of operations of the Covert Plant and the DIG, Kalamazoo, and Livingston plants by May 31, 2040, however, the final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets. The Company remains committed to its Net Zero Carbon Emissions goal by 2040 and continues to be engaged and involved in partnerships with Electric Power Research Institute ("EPRI") on its carbon initiatives and other avenues. The Company's 200 ZRCs capacity surplus to address execution risks was applied to 2040. Figure 9 below shows the incremental capacity of resources to the base capacity position described above and shown in Figure 5. The Company's capacity position achieves a significant surplus in the late 2020s, and again in

the late 2030s, as the Company builds its resource portfolio in preparation for the capacity losses from expiring or retiring supply resources. This surplus serves as a prudent hedge against potential execution and delivery risks with adding demand-side management programs and the significant levels of solar generation. The modular approach of adding smaller portions of supply on a yearly basis allows the Company to be flexible in its resource planning—providing the opportunity to evolve and adapt to changing conditions. Note that the Company's capacity position returns to near zero in years 2031 and 2040, indicating that the backfill plan provides sufficient capacity for the expiration of the MCV PPA as well as the generating assets that retire in 2031 and 2040.

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



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

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

A. The Company used Aurora to first conduct a capacity expansion analysis to serve the capacity and energy needs of projected customer demand for: (i) continued operation of Karn Units 3 and 4 and Campbell Units 1 and 2, versus (ii) the accelerated retirement of

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

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

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

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

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

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

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

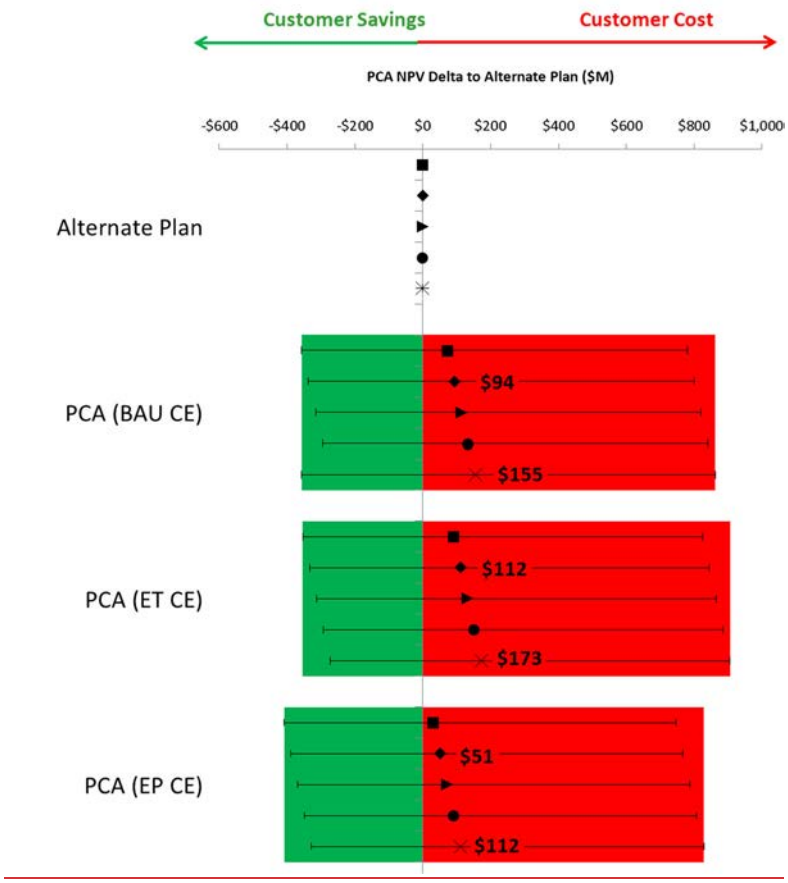
The economic analysis of retiring Campbell Units 1 and 2 in isolation showed minimal changes in years 2024, 2025, and 2026. The units in isolation show improvement in economics if one of the units were retired prior to the year 2028 at which point environmental expenditures are no longer avoidable. Similar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

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

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

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

Figure 11 Revised: Alternate Plan versus PCA



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

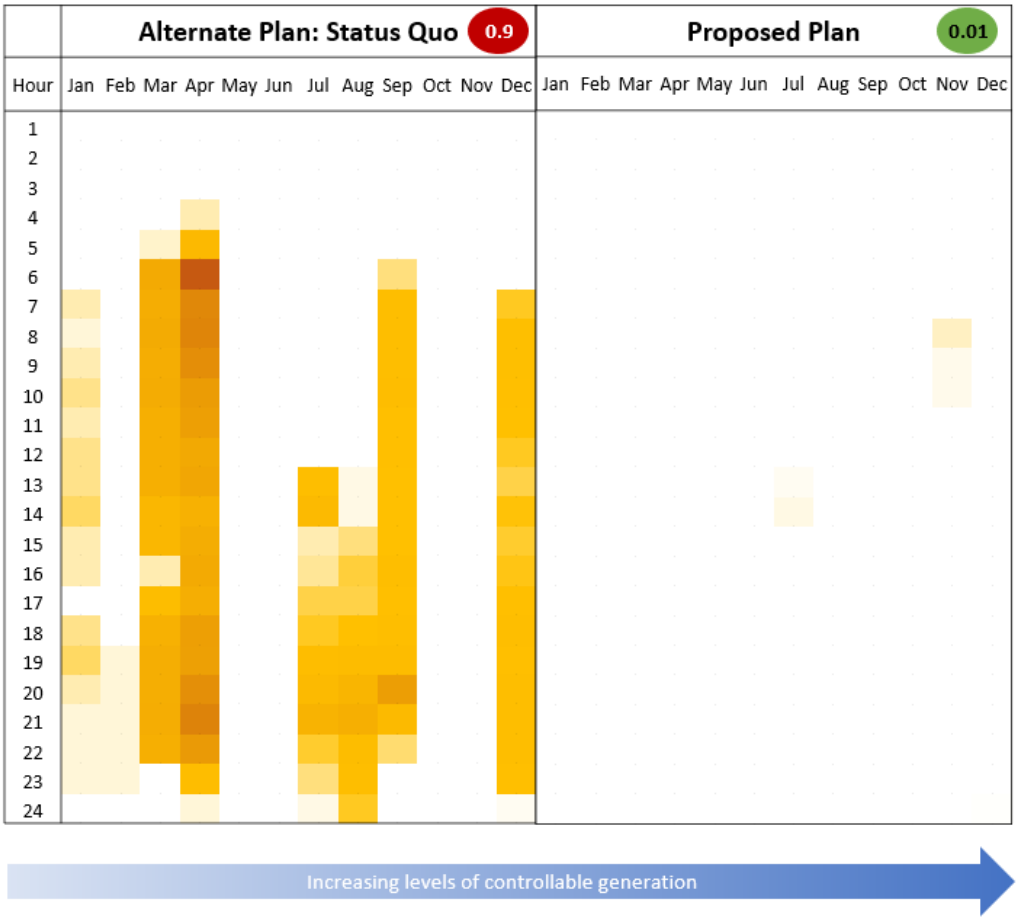
of solar, batteries, and demand-side management programs in a manner similar to the 2018 IRP.

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

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

needs under a stress test of various parameters effecting reliability (i.e. generator availability, DR availability, load changes).

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



The NERC standard for regional reliability is a probability that no less than 1 day in 10 years results in the loss of load. The study conducted by the Company determines an average LOLE of 1 day in 10 years to equate to the NERC standard. If a plan achieves an average LOLE of 0.1 or less the plan is sufficient in meeting capacity and energy needs. An average LOLE greater than 0.1 indicates deteriorating capacity sufficiency. The analysis clearly indicates improved reliability in all hours of the year with the use of controllable generation. Batteries were considered as a possible resource to meet times of

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

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

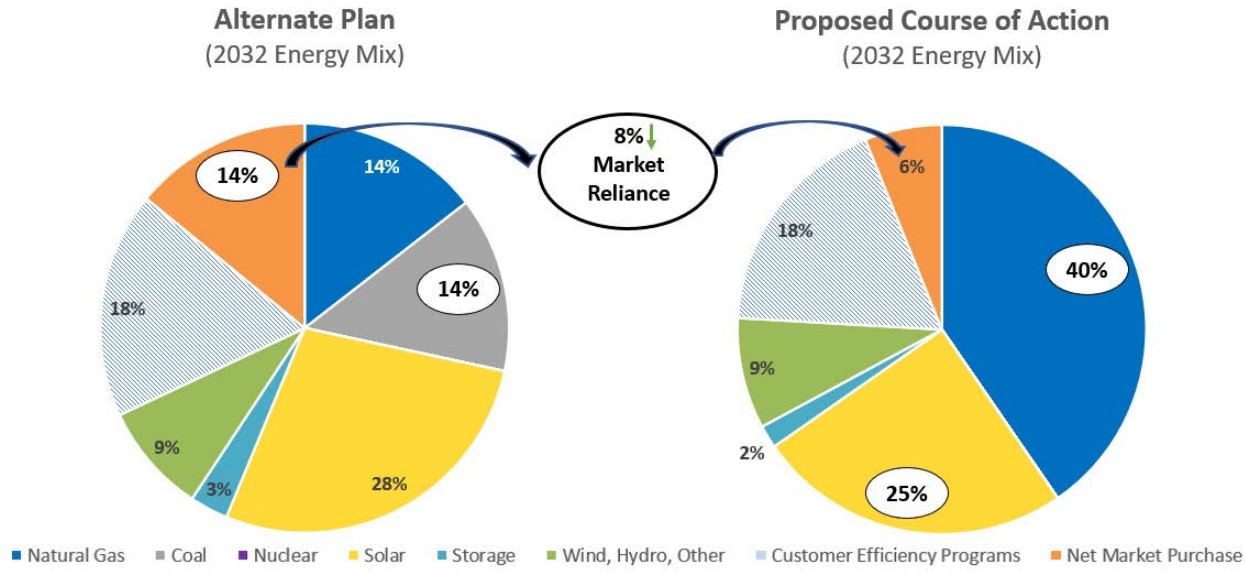
The resulting PCA compared to the base Alternate Plan clearly finds the Company's PCA to be superior in providing long-term capacity sufficiency in all seasons and in every hour of every day. Details on MISO constructs and system operability are discussed in the direct testimony of Company witness Clark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

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

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

customers, whether to economically dispatch the controllable generation or rely on economic energy from the market. The operational cycling capabilities of the Covert, DIG, Kalamazoo, and Livingston plants as gas units, versus coal units, enhances the Company's level of responsiveness to market signals related to dispatch of resources. Figure 13 is a comparison of the energy reliance between the Alternate Plan and the PCA. The direct testimony of Company witness Clark further discusses market reliance.

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



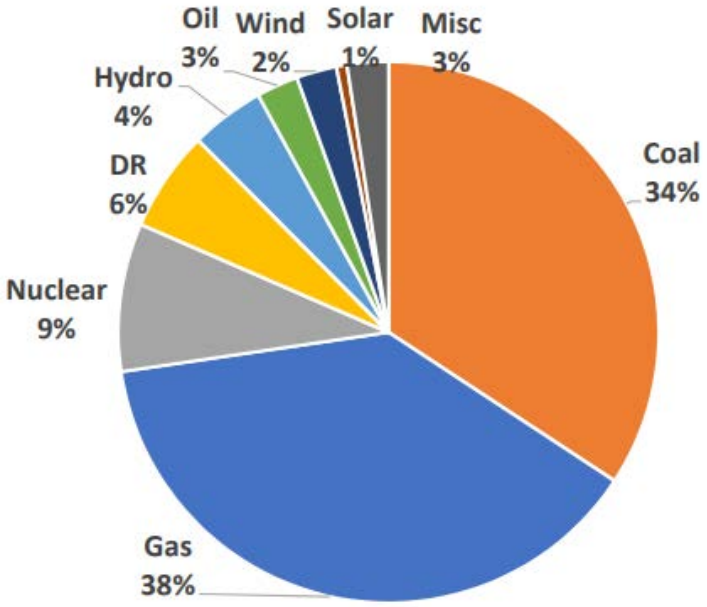
Lastly, a transmission analysis was conducted for the cases retiring Karn Units 3 and 4 in 2023, retiring Campbell Units 1 and 2 as early as 2024, and retirement of Karn Units 3 and 4 in 2023 with the retirement of Campbell Units 1, 2, and 3 in the year 2025 (reflective of the PCA). The transmission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

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

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

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

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

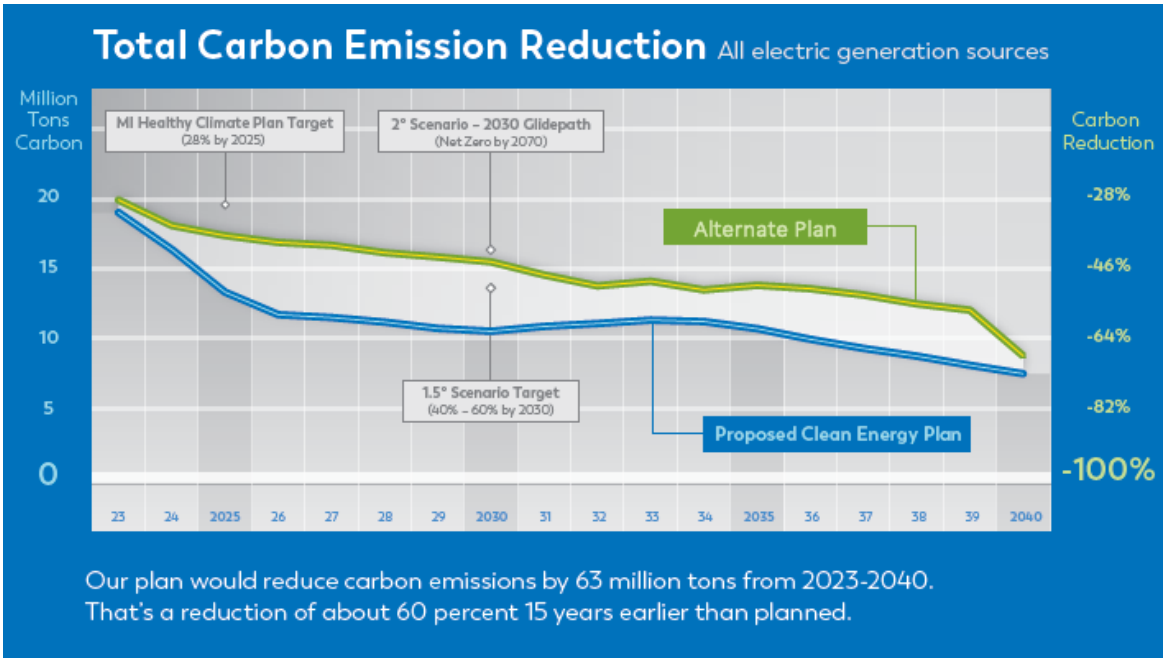


The Alternate Plan (status quo 2018 IRP) relies heavily on market purchases and continued investments in the coal units to allow for continued operations through 2039. The PCA reduces carbon emissions when compared to the Alternate Plan by 63 million tons, which is eliminating about 5.5 years of emissions,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

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

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

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



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

A. The employee impact assessment for the accelerated retirement of Karn Units 3 and 4 identified approximately 80 employees impacted. The accelerated retirement of Campbell

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

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

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

A. Consumers Energy has a process for Just Transition that involves four phases: (1) a commitment to fair and equitable treatment of impacted employees and communities;

(2) gathering information through engagement with the community and stakeholders; (3) visualizing scenarios to implement; and (4) implementing solutions. Consumers Energy continues to be fully committed to community stakeholder collaboration and an orderly transition process at each of its remaining sites.

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

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

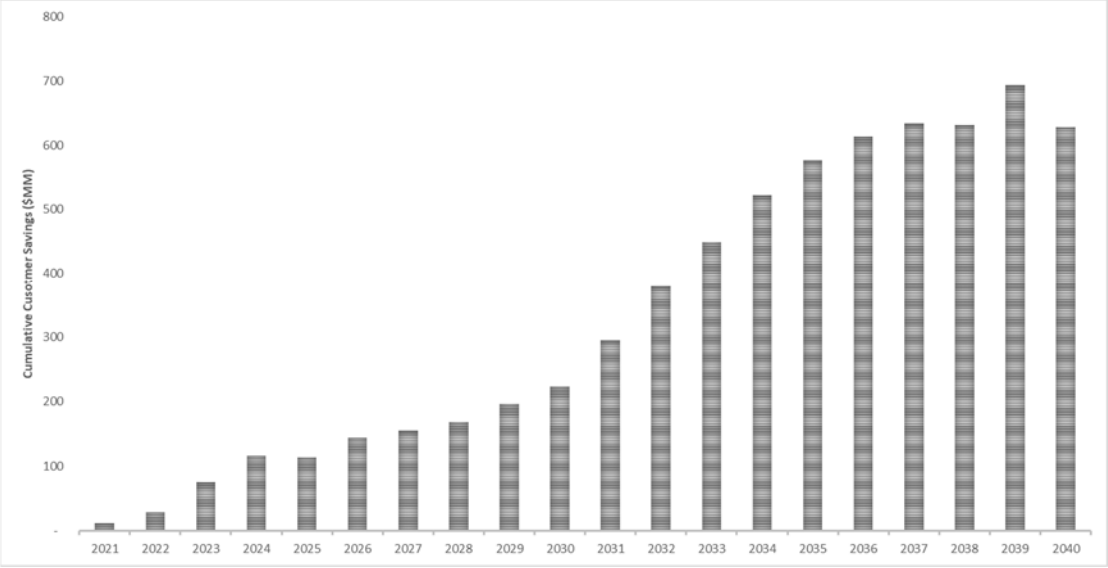
Through the Company's experience, Consumers Energy has learned that engaging its employees and communities as early as possible is critical for gathering information and developing solutions that work because these efforts take time. In addition, as the Company expands its reach through the 2021 IRP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

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

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

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

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



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

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

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

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

1) $~~640~~ 628 million cumulative savings for customers by accelerating retirement of coal and oil/gas peaking units replaced with the Covert, DIG, Kalamazoo, and Livingston plants (reference direct testimony of Company witness Coker);

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants by Consumers Energy from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct requirements. The competitive solicitation also complied with FERC's standards for determining that an acquisition involving an affiliate will not adversely affect competition and is consistent with the public interest as it satisfied the four principles – Transparency, Definition, Evaluation, and Oversight – of FERC's solicitation guidelines. In the alternative, while complying with all other provisions of the Code of Conduct, the Company requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Kalamazoo, and Livingston plants from CMS Enterprises;

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

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

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

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

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

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

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

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

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

Q. Please summarize your direct testimony.

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

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

Q. Does this complete your direct testimony?

A. Yes, it does.

Attachment EE

JH Campbell ROP

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

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

ISSUED TO

Consumers Energy, J.H. Campbell Generating Complex

State Registration Number (SRN): B2835

LOCATED AT

17000 Croswell, West Olive, Ottawa County, Michigan 49460

RENEWABLE OPERATING PERMIT

Permit Number: MI-ROP-B2835-2020b

Expiration Date: February 4, 2025

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

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

SOURCE-WIDE PERMIT TO INSTALL

Permit Number: MI-PTI-B2835-2020b

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

Michigan Department of Environment, Great Lakes, and Energy

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Heidi Hollenbach, Grand Rapids District Supervisor

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AUTHORITY AND ENFORCEABILITY

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

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

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

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

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

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

A. GENERAL CONDITIONS

Permit Enforceability

- All conditions in this permit are both federally enforceable and state enforceable unless otherwise noted. **(R 336.1213(5))**

- Those conditions that are hereby incorporated in a state-only enforceable Source-Wide PTI pursuant to Rule 201(2)(d) are designated by footnote one. **(R 336.1213(5)(a), R 336.1214a(5))**

- Those conditions that are hereby incorporated in a federally enforceable Source-Wide PTI pursuant to Rule 201(2)(c) are designated by footnote two. **(R 336.1213(5)(b), R 336.1214a(3))**

General Provisions

1. The permittee shall comply with all conditions of this ROP. Any ROP noncompliance constitutes a violation of Act 451, and is grounds for enforcement action, for ROP revocation or revision, or for denial of the renewal of the ROP. All terms and conditions of this ROP that are designated as federally enforceable are enforceable by the Administrator of the United States Environmental Protection Agency (USEPA) and by citizens under the provisions of the federal Clean Air Act (CAA). Any terms and conditions based on applicable requirements which are designated as "state-only" are not enforceable by the USEPA or citizens pursuant to the CAA. **(R 336.1213(1)(a))**

2. It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this ROP. **(R 336.1213(1)(b))**

3. This ROP may be modified, revised, or revoked for cause. The filing of a request by the permittee for a permit modification, revision, or termination, or a notification of planned changes or anticipated noncompliance does not stay any ROP term or condition. This does not supersede or affect the ability of the permittee to make changes, at the permittee's own risk, pursuant to Rule 215 and Rule 216. **(R 336.1213(1)(c))**

4. The permittee shall allow the department, or an authorized representative of the department, upon presentation of credentials and other documents as may be required by law and upon stating the authority for and purpose of the investigation, to perform any of the following activities: **(R 336.1213(1)(d))**
   a. Enter, at reasonable times, a stationary source or other premises where emissions-related activity is conducted or where records must be kept under the conditions of the ROP.
   b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the ROP.
   c. Inspect, at reasonable times, any of the following:
      i. Any stationary source.
      ii. Any emission unit.
      iii. Any equipment, including monitoring and air pollution control equipment.
      iv. Any work practices or operations regulated or required under the ROP.
   d. As authorized by Section 5526 of Act 451, sample or monitor at reasonable times substances or parameters for the purpose of assuring compliance with the ROP or applicable requirements.

5. The permittee shall furnish to the department, within a reasonable time, any information the department may request, in writing, to determine whether cause exists for modifying, revising, or revoking the ROP or to determine compliance with this ROP. Upon request, the permittee shall also furnish to the department copies of any records that are required to be kept as a term or condition of this ROP. For information which is claimed by the permittee to be confidential, consistent with the requirements of the 1976 PA 442, MCL §15.231 et seq., and known as the Freedom of Information Act, the person may also be required to furnish the records directly to the USEPA together with a claim of confidentiality. **(R 336.1213(1)(e))**

6. A challenge by any person, the Administrator of the USEPA, or the department to a particular condition or a part of this ROP shall not set aside, delay, stay, or in any way affect the applicability or enforceability of any other condition or part of this ROP. **(R 336.1213(1)(f))**

7. The permittee shall pay fees consistent with the fee schedule and requirements pursuant to Section 5522 of Act 451. **(R 336.1213(1)(g))**

8. This ROP does not convey any property rights or any exclusive privilege. **(R 336.1213(1)(h))**

Equipment & Design

9. Any collected air contaminants shall be removed as necessary to maintain the equipment at the required operating efficiency. The collection and disposal of air contaminants shall be performed in a manner so as to minimize the introduction of contaminants to the outer air. Transport of collected air contaminants in Priority I and II areas requires the use of material handling methods specified in Rule 370(2).[2] **(R 336.1370)**

10. Any air cleaning device shall be installed, maintained, and operated in a satisfactory manner and in accordance with the Michigan Air Pollution Control rules and existing law. **(R 336.1910)**

Emission Limits

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

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

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

Testing/Sampling

13. The department may require the owner or operator of any source of an air contaminant to conduct acceptable performance tests, at the owner's or operator's expense, in accordance with Rule 1001 and Rule 1003, under any of the conditions listed in Rule 1001(1).[2] **(R 336.2001)**

14. Any required performance testing shall be conducted in accordance with Rule 1001(2), Rule 1001(3) and Rule 1003. **(R 336.2001(2), R 336.2001(3), R 336.2003(1))**

15. Any required test results shall be submitted to the Air Quality Division (AQD) in the format prescribed by the applicable reference test method within 60 days following the last date of the test. **(R 336.2001(5))**

Monitoring/Recordkeeping

16. Records of any periodic emission or parametric monitoring required in this ROP shall include the following information specified in Rule 213(3)(b)(i), where appropriate. **(R 336.1213(3)(b))**
    a. The date, location, time, and method of sampling or measurements.
    b. The dates the analyses of the samples were performed.
    c. The company or entity that performed the analyses of the samples.
    d. The analytical techniques or methods used.
    e. The results of the analyses.
    f. The related process operating conditions or parameters that existed at the time of sampling or measurement.

17. All required monitoring data, support information and all reports, including reports of all instances of deviation from permit requirements, shall be kept and furnished to the department upon request for a period of not less than 5 years from the date of the monitoring sample, measurement, report or application. Support information includes all calibration and maintenance records and all original strip-chart recordings, or other original data records, for continuous monitoring instrumentation and copies of all reports required by the ROP. **(R 336.1213(1)(e), R 336.1213(3)(b)(ii))**

Certification & Reporting

18. Except for the alternate certification schedule provided in Rule 213(3)(c)(iii)(B), any document required to be submitted to the department as a term or condition of this ROP shall contain an original certification by a Responsible Official which state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete. **(R 336.1213(3)(c))**

19. A Responsible Official shall certify to the appropriate AQD District Office and to the USEPA that the stationary source is and has been in compliance with all terms and conditions contained in the ROP except for deviations that have been or are being reported to the appropriate AQD District Office pursuant to Rule 213(3)(c). This certification shall include all the information specified in Rule 213(4)(c)(i) through (v) and shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the certification are true, accurate, and complete. The USEPA address is: USEPA, Air Compliance Data - Michigan, Air and Radiation Division, 77 West Jackson Boulevard, Chicago, Illinois 60604-3507. **(R 336.1213(4)(c))**

20. The certification of compliance shall be submitted annually for the term of this ROP as detailed in the special conditions, or more frequently if specified in an applicable requirement or in this ROP. **(R 336.1213(4)(c))**

21. The permittee shall promptly report any deviations from ROP requirements and certify the reports. The prompt reporting of deviations from ROP requirements is defined in Rule 213(3)(c)(ii) as follows, unless otherwise described in this ROP. **(R 336.1213(3)(c))**
    a. For deviations that exceed the emissions allowed under the ROP, prompt reporting means reporting consistent with the requirements of Rule 912 as detailed in Condition 25. All reports submitted pursuant to this paragraph shall be promptly certified as specified in Rule 213(3)(c)(iii).
    b. For deviations which exceed the emissions allowed under the ROP and which are not reported pursuant to Rule 912 due to the duration of the deviation, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe reasons for each deviation and the actions taken to minimize or correct each deviation.
    c. For deviations that do not exceed the emissions allowed under the ROP, prompt reporting means the reporting of all deviations in the semiannual reports required by Rule 213(3)(c)(i). The report shall describe the reasons for each deviation and the actions taken to minimize or correct each deviation.

22. For reports required pursuant to Rule 213(3)(c)(ii), prompt certification of the reports is described in Rule 213(3)(c)(iii) as either of the following: **(R 336.1213(3)(c))**
    a. Submitting a certification by a Responsible Official with each report which states that, based on information and belief formed after reasonable inquiry, the statements and information in the report are true, accurate, and complete.
    b. Submitting, within 30 days following the end of a calendar month during which one or more prompt reports of deviations from the emissions allowed under the ROP were submitted to the department pursuant to Rule 213(3)(c)(ii), a certification by a Responsible Official which states that; "based on information and belief formed after reasonable inquiry, the statements and information contained in each of the reports submitted during the previous month were true, accurate, and complete." The certification shall include a listing of the reports that are being certified. Any report submitted pursuant to Rule 213(3)(c)(ii) that will be certified on a monthly basis pursuant to this paragraph shall include a statement that certification of the report will be provided within 30 days following the end of the calendar month.

23. Semiannually for the term of the ROP as detailed in the special conditions, or more frequently if specified, the permittee shall submit certified reports of any required monitoring to the appropriate AQD District Office. All instances of deviations from ROP requirements during the reporting period shall be clearly identified in the reports. **(R 336.1213(3)(c)(i))**

24. On an annual basis, the permittee shall report the actual emissions, or the information necessary to determine the actual emissions, of each regulated air pollutant as defined in Rule 212(6) for each emission unit utilizing the emissions inventory forms provided by the department. **(R 336.1212(6))**

25. The permittee shall provide notice of an abnormal condition, start-up, shutdown, or malfunction that results in emissions of a hazardous or toxic air pollutant which continue for more than one hour in excess of any applicable standard or limitation, or emissions of any air contaminant continuing for more than two hours in excess of an applicable standard or limitation, as required in Rule 912, to the appropriate AQD District Office. The notice shall be provided not later than two business days after the start-up, shutdown, or discovery of the abnormal conditions or malfunction. Notice shall be by any reasonable means, including electronic, telephonic, or oral communication. Written reports, if required under Rule 912, must be submitted to the appropriate AQD District Supervisor within 10 days after the start-up or shutdown occurred, within 10 days after the abnormal conditions or malfunction has been corrected, or within 30 days of discovery of the abnormal conditions or malfunction, whichever is first. The written reports shall include all of the information required in Rule 912(5) and shall be certified by a Responsible Official in a manner consistent with the CAA.[2] **(R 336.1912)**

Permit Shield

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

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

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

d. The ability of the USEPA to obtain information from a source pursuant to Section 114 of the CAA. **(R 336.1213(6)(b)(iv))**

28. The permit shield shall not apply to provisions incorporated into this ROP through procedures for any of the following:
    a. Operational flexibility changes made pursuant to Rule 215. **(R 336.1215(5))**
    b. Administrative Amendments made pursuant to Rule 216(1)(a)(i)-(iv). **(R 336.1216(1)(b)(iii))**
    c. Administrative Amendments made pursuant to Rule 216(1)(a)(v) until the amendment has been approved by the department. **(R 336.1216(1)(c)(iii))**
    d. Minor Permit Modifications made pursuant to Rule 216(2). **(R 336.1216(2)(f))**
    e. State-Only Modifications made pursuant to Rule 216(4) until the changes have been approved by the department. **(R 336.1216(4)(e))**

29. Expiration of this ROP results in the loss of the permit shield. If a timely and administratively complete application for renewal is submitted not more than 18 months, but not less than 6 months, before the expiration date of the ROP, but the department fails to take final action before the end of the ROP term, the existing ROP does not expire until the renewal is issued or denied, and the permit shield shall extend beyond the original ROP term until the department takes final action. **(R 336.1217(1)(c), R 336.1217(1)(a))**

Revisions

30. For changes to any process or process equipment covered by this ROP that do not require a revision of the ROP pursuant to Rule 216, the permittee must comply with Rule 215. **(R 336.1215, R 336.1216)**

31. A change in ownership or operational control of a stationary source covered by this ROP shall be made pursuant to Rule 216(1). **(R 336.1219(2))**

32. For revisions to this ROP, an administratively complete application shall be considered timely if it is received by the department in accordance with the time frames specified in Rule 216. **(R 336.1210(10))**

33. Pursuant to Rule 216(1)(b)(iii), Rule 216(2)(d) and Rule 216(4)(d), after a change has been made, and until the department takes final action, the permittee shall comply with both the applicable requirements governing the change and the ROP terms and conditions proposed in the application for the modification. During this time period, the permittee may choose to not comply with the existing ROP terms and conditions that the application seeks to change. However, if the permittee fails to comply with the ROP terms and conditions proposed in the application during this time period, the terms and conditions in the ROP are enforceable. **(R 336.1216(1)(c)(iii), R 336.1216(2)(d), R 336.1216(4)(d))**

Reopenings

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

Renewals

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

Stratospheric Ozone Protection

36. If the permittee is subject to Title 40 of the Code of Federal Regulations (CFR), Part 82 and services, maintains, or repairs appliances except for motor vehicle air conditioners (MVAC), or disposes of appliances containing refrigerant, including MVAC and small appliances, or if the permittee is a refrigerant reclaimer, appliance owner or a manufacturer of appliances or recycling and recovery equipment, the permittee shall comply with all applicable standards for recycling and emissions reduction pursuant to 40 CFR Part 82, Subpart F.

37. If the permittee is subject to 40 CFR Part 82 and performs a service on motor (fleet) vehicles when this service involves refrigerant in the MVAC, the permittee is subject to all the applicable requirements as specified in 40 CFR Part 82, Subpart B, Servicing of Motor Vehicle Air Conditioners. The term “motor vehicle” as used in Subpart B does not include a vehicle in which final assembly of the vehicle has not been completed by the original equipment manufacturer. The term MVAC as used in Subpart B does not include the air-tight sealed refrigeration system used for refrigerated cargo or an air conditioning system on passenger buses using Hydrochlorofluorocarbon-22 refrigerant.

Risk Management Plan

38. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall register and submit to the USEPA the required data related to the risk management plan for reducing the probability of accidental releases of any regulated substances listed pursuant to Section 112(r)(3) of the CAA as amended in 40 CFR 68.130. The list of substances, threshold quantities, and accident prevention regulations promulgated under 40 CFR Part 68, do not limit in any way the general duty provisions under Section 112(r)(1).

39. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall comply with the requirements of 40 CFR Part 68, no later than the latest of the following dates as provided in 40 CFR 68.10(a):
    a. June 21, 1999,
    b. Three years after the date on which a regulated substance is first listed under 40 CFR 68.130, or
    c. The date on which a regulated substance is first present above a threshold quantity in a process.

40. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall submit any additional relevant information requested by any regulatory agency necessary to ensure compliance with the requirements of 40 CFR Part 68.

41. If subject to Section 112(r) of the CAA and 40 CFR Part 68, the permittee shall annually certify compliance with all applicable requirements of Section 112(r) as detailed in Rule 213(4)(c)). **(40 CFR Part 68)**

Emission Trading

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

Permit to Install (PTI)

43. The process or process equipment included in this permit shall not be reconstructed, relocated, or modified unless a PTI authorizing such action is issued by the department, except to the extent such action is exempt from the PTI requirements by any applicable rule.[2] **(R 336.1201(1))**

44. The department may, after notice and opportunity for a hearing, revoke PTI terms or conditions if evidence indicates the process or process equipment is not performing in accordance with the terms and conditions of the PTI or is violating the department's rules or the CAA.[2] **(R 336.1201(8), Section 5510 of Act 451)**

45. The terms and conditions of a PTI shall apply to any person or legal entity that now or hereafter owns or operates the process or process equipment at the location authorized by the PTI. If a new owner or operator submits a written request to the department pursuant to Rule 219 and the department approves the request, this PTI will be amended to reflect the change of ownership or operational control. The request must include all of the information required by Subrules (1)(a), (b) and (c) of Rule 219. The written request shall be sent to the appropriate AQD District Supervisor, EGLE.[2] **(R 336.1219)**

46. If the installation, reconstruction, relocation, or modification of the equipment for which PTI terms and conditions have been approved has not commenced within 18 months of the original PTI issuance date, or has been interrupted for 18 months, the applicable terms and conditions from that PTI, as incorporated into the ROP, shall become void unless otherwise authorized by the department. Furthermore, the person to whom that PTI was issued, or the designated authorized agent, shall notify the department via the Supervisor, Permit Section, EGLE, AQD, P. O. Box 30260, Lansing, Michigan 48909, if it is decided not to pursue the installation, reconstruction, relocation, or modification of the equipment allowed by the terms and conditions from that PTI.[2] **(R 336.1201(4))**

Footnotes:
[1]This condition is state-only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

B. SOURCE-WIDE CONDITIONS

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

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

C. EMISSION UNIT SPECIAL CONDITIONS

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

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

EMISSION UNIT SUMMARY TABLE

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

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

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

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

EUBOILER1
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

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

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.16 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER1	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.220 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 76; Act 451, Section 324.5503(b)**
3. SO_2	0.350 pounds per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4. SO_2	0.290 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER1	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 113; Act 451, Section 324.5503(b)**
5. PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER1	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 144; Act 451, Section 324.5503(b)**
6. Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER1	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**
7. SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER1	SC VI.3	**R 336.1401(3), Table 41**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER1 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER1 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

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

2. The permittee shall continuously operate the PM Control Device for EUBOILER1 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER1 unless the low-NOx burners, the DSI, the ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER1 control equipment as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER1 unless the low-NO_x burners, including over fire air processes, are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 75, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER1 unless the DSI system is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 113, Act 451, Section 324.5503(b))**

4. The permittee shall not operate EUBOILER1 unless the PJFF baghouse unit is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 144, Act 451, Section 324.5503(b))**

5. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

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

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER1 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A, Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5 or "MATS" 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.2001, R 336.2003, R 336.2004)**
2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor not less than 7 days of the time and place before performance tests are conducted.[2] **(R 336.2001(3))**

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor unit level SO_2 concentrations and gas flow, using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR Part 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR Part 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS-MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER2
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: FGBOILER12 and FGMATS_U12

POLLUTION CONTROL EQUIPMENT

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

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Particulate matter (PM)	0.15 pound per 1,000 pounds exhaust gas, corrected to 50% excess air[2]	Hourly	EUBOILER2	SC V.1 (FGBOILER12, SC VI.1, COMS)	**R 336.1331(1)(c)**
2. NO_x	0.100 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 78; Act 451, Section 324.5503(b)**
3. NO_x	0.080 pound per MMBTU heat input[2,3,4]	Based on a 90-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 79; Act 451, Section 324.5503(b)**

	Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
4.	SO_2	0.320 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER2	SC VI.1 SC VI.2	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 114; Act 451, Section 324.5503(b)**
5.	PM	0.015 pound per MMBTU heat input[2,3,4]	Hourly[2,3,4]	EUBOILER2	SC V.2 (FGBOILER12, SC VI.1, COMS)	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 145; Act 451, Section 324.5503(b)**
6.	SO_2	1.67 pounds per MMBTU heat input[2]	Monthly average, based on the average of the 31 previous operating days	EUBOILER2	SC VI.3	**R 336.1401(3), Table 41**
7.	Opacity	20%[2,3,4]	Per 6-minute period except for one 6-minute period per hour of not more than 27%[2,3,4]	EUBOILER2	SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 151; Act 451, Section 324.5503(b)**

8. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER2 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

9. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendices 11-A and 11-B

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUBOILER2 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for the emission control equipment (PJFF baghouse, ACI, DSI, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

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

2. The permittee shall continuously operate the PM Control Device for EUBOILER2 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

3. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

4. The permittee shall not burn freeze conditioning/dust suppression agents unless PJFF baghouses are installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER2 unless the low-NOx burners, the SCR, DSI, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER2 as required in SC III.1.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER2 unless the SCR and PJFF baghouse are continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 77 and 145, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER2 unless the DSI system is continuously operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 114, Act 451, Section 324.5503(b))**

4. The permittee shall continuously operate the PM control devices being vented to a combined stack associated with FGBOILER12.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 142, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

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

1. Every three (3) years, or more frequently upon request of the AQD, the permittee shall verify PM emission rates from EUBOILER2 by testing at the owner's expense, in accordance with the Department requirements. Testing shall be performed using an approved USEPA Method listed in 40 CFR Part 60, Appendix A Reference Method 17 (Determination of Particulate Emissions from Stationary Sources (In-stack Filtration Method)), Reference Method 5, "MATS" Reference Method 5, or other acceptable test method(s). An alternate method, or a modification to the approved USEPA Method, may be specified in an AQD-approved Test Protocol. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(R 336.1213(3), R 336.1201(3), R 336.2001, R 336.2003, R 336.2004)**

2. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

3. The permittee shall notify the AQD Technical Programs Unit Supervisor and the District Supervisor no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.2, I.3, and I.4., the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

2. The permittee shall monitor SO_2 concentrations and gas flow using CEMS, as installed, maintained, and operated in accordance with 40 CFR Part 75.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 116, Act 451, Section 324.5503(b))**

3. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1401, R 336.2101)**

4. The permittee shall monitor and record the opacity from each boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101)**

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with all applicable requirements of 40 CFR Part 64 as specified in FGBOILER12. **(40 CFR Part 64)**

8. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units, as specified in FGMATS_U12.[2] **(40 CFR Part 63, Subpart UUUUU)**

See Appendices 11-A and 11-B

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

EUBOILER3
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: FGMATS_U3

POLLUTION CONTROL EQUIPMENT

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

I. EMISSION LIMIT(S)

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

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
6. PM	0.015 pound per MMBTU heat input[2,3,4]	Based on a 3-hr rolling average in accordance with SC V.4 and SC VI.4[2,3,4]	EUBOILER3	SC V.3, SC V.4 (if applicable) SC VI.4	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 146; Act 451, Section 324.5503(b)**
7. SO_2	1.2 pounds per MMBTU heat input[2]	Continuous	EUBOILER3	SC VI.1	**40 CFR 60.43(a)(2)**
8. SO_2	10,500 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
9. SO_2	31,650 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**
10. SO_2	0.085 pound per MMBTU heat input[2,3,4]	Based on a 30-day Rolling Average[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
11. SO_2	0.070 pound per MMBTU heat input[2,3,4]	Based on a 365-day Rolling Average Emission Rate[2,3,4]	EUBOILER3	SC VI.3	**"U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraph 112; Act 451, Section 324.5503(b)**
12. NOx	0.70 pound per MMBTU heat input[2]	Per 3-hour rolling time period, as determined each hour the boiler operates	EUBOILER3	SC VI.1	**40 CFR 60.44(a)(3)**
13. NOx	6,130 pounds per hour[2]	Based on a daily average	EUBOILER3	SC VI.1	**R 336.1205(3)**
14. NOx	18,750 tons per year[2]	Based on a 12-month rolling time period as determined at the end of each calendar month	EUBOILER3	SC VI.1	**R 336.1205(3)**

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

17. The permittee shall comply with the System-Wide Annual NOx Tonnage Limitations and System-Wide Annual SO_2 Tonnage Limitations specified in Appendix 11-A. Emissions from EUBOILER3 shall be counted toward the system-wide total emissions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 98 & 129, Act 451, Section 324.5503(b))**

18. The permittee shall comply with the SO_2 and NO_x allowance surrender and super-compliance allowance provisions listed in Appendix 11-B: Allowance Provisions.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 101-109 and 132-140, Act 451, Section 324.5503(b))**

See Appendix 11-A and Appendix 11-B

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not burn freeze conditioning/dust suppression agents unless the boiler and corresponding particulate control device are operating properly.[2] **(R 336.1910)**

2. The permittee shall not operate the boiler, including startup and shutdown, unless the corresponding PJFF baghouse is installed and operating properly, in accordance with safe operating practices.[2] **(R 336.1910)**

3. The permittee shall not operate EUBOILER3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment (PJFF baghouse, ACI, SDA, and SCR) is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

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

4. The permittee shall comply with all provisions of the federal Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced after August 17, 1971, as specified in 40 CFR Part 60, Subparts A and D, as they apply to EUBOILER3.[2] **(40 CFR Part 60, Subparts A and D)**

5. The permittee shall continuously operate the PM Control Device for EUBOILER3 and use good air pollution control practices to maximize the PM emission reductions at all times when the unit is in operation. The requirements of Appendix 3-F shall be met.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 141, Act 451, Section 324.5503(b))**

See Appendix 3-F

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate EUBOILER3 unless the low-NOx burners, the SCR, SDA, ACI sorbent injection (for mercury control), and PJFF baghouse are installed, maintained, and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approvable MAP for EUBOILER3 as required in SC III.5.[2] **(R 336.1910)**

2. The permittee shall not operate EUBOILER3 unless the SCR is Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 80, Act 451, Section 324.5503(b))**

3. The permittee shall not operate EUBOILER3 unless the SDA and PJFF baghouse units are Continuously Operated.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraphs 112 and 146, Act 451, Section 324.5503(b))**

V. TESTING/SAMPLING

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

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

2. The permittee shall notify the AQD no less than 7 days prior to the anticipated test date.[2] **(R 336.2001(3))**

3. The permittee shall conduct a stack test for PM pursuant to the provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements. Subsequent stack tests for PM shall be conducted pursuant to the schedule and provisions found in Appendix 5: PM Emissions Testing and Monitoring Requirements.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 153, Act 451, Section 324.5503(b))**

4. As an alternative to the requirements of SC V.3 PM stack testing, the permittee may forego stack testing and instead demonstrate continuous compliance with SC I.7 PM filterable emission limit by using the PM CEMS pursuant to conditions contained in Appendix 5: PM Emissions Testing and Monitoring Requirements, and Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" – paragraph 157, Act 451, Section 324.5503(b))**

See Appendices 3-E and 5

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall monitor gas flow, SO_2, CO_2, and NOx emissions using CEMS, as installed, maintained, and operated in accordance with the provisions of 40 CFR Part 75.[2] **(R 336.1205(3), R 336.2101, 40 CFR Part 60)**

2. The permittee shall monitor and record the opacity from the boiler using a Continuous Opacity Monitoring System (COMS), installed, operated and maintained in accordance with 40 CFR Part 60, Appendix B.[2] **(R 336.1301, R 336.2101, 40 CFR 60.42(a)(2))**

3. For purposes of determining compliance with the Rolling Average Emission Rates for NO_x and SO_2 as found in SC I.10, I.11, I.15, and I.16, the permittee shall install and operate CEMS in accordance with the procedures of 40 CFR Part 75, except that the NO_x and SO_2 emissions data need not be bias adjusted and the missing data substitution procedures of 40 CFR Part 75 shall not apply. If applicable, diluent capping (i.e., 5% CO_2) will be applied to the NO_x emission rate for any hours where the measured CO_2 concentration is less than 5% following the procedures in 40 CFR Part 75, Appendix F, Section 3.3.4.1.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 99 and 130, Act 451, Section 324.5503(b))**

4. The permittee shall install and continuously operate a PM CEMS pursuant to the conditions contained in Appendix 3-E: PM CEMS.[2,3,4] **("U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" paragraphs 159, 163, Act 451, Section 324.5503(b))**

See Appendices 3-A through 3-F

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports, including RATA reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

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

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

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the acid rain permitting provisions of 40 CFR 72.1 to 72.94, as outlined in a complete Phase II, Acid Rain Permit issued by the AQD. Phase II, Acid Rain Permit No. MI-AR-1710-2020 is hereby incorporated into this ROP as Appendix 9. **(R 336.1902(1)(q))**

2. The permittee shall not allow the emission of an air pollutant to exceed the amount of any emission allowances that an affected source lawfully holds as of the allowance transfer deadline pursuant to R 336.1902(1)(q) and 40 CFR 72.9(c)(1)(i). **(R 336.1213(10))**

3. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Annual Trading Program, as specified in 40 CFR Part 97, Subpart AAAAA, and identified in Appendix 10. **(40 CFR Part 97, Subpart AAAAA)**

4. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule NO_X Ozone Season Group 2 Trading Program, as specified in 40 CFR Part 97, Subpart EEEEE, and identified in Appendix 10. **(40 CFR Part 97, Subpart EEEEE)**

5. The permittee shall comply with the provisions of the Cross-State Air Pollution Rule SO_2 Group 1 Trading Program, as specified in 40 CFR Part 97, Subpart CCCCC, and identified in Appendix 10. **(40 CFR Part 97, Subpart CCCCC)**

6. The permittee shall comply with applicable provisions of Act 451 Part 15 EMISSION LIMITATIONS AND PROHIBITIONS—MERCURY.[2] **(R 336.2503(1))**

7. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart UUUUU - National Emission Standards for Hazardous Air Pollutants: Coal- and Oil-fired Electric Utility Steam Generating Units as specified in FGMATS_U3.[2] **(40 CFR Part 63, Subpart UUUUU)**

Footnotes:

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

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

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

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

EUCOALHAND
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

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

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

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

I. EMISSION LIMIT(S)

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate a process portion unless the particulate matter control device controlling the portion is installed and operating properly. **(R 336.1910)**

2. The permittee shall operate all coal handling equipment in accordance with the most recent facility Fugitive Dust Control Plan as approvable by the AQD District Supervisor. **(R 336.1213(3))**

3. The permittee shall not operate EUCOALHAND unless a malfunction abatement plan (MAP) as described in Rule 911(2), for emission control equipment is implemented and maintained. The MAP shall, at a minimum, specify the following:

   a. A complete preventative maintenance program including identification of the supervisory personnel responsible for overseeing the inspection, maintenance, and repair of air-cleaning devices, a description of the items or conditions that shall be inspected, the frequency of the inspections or repairs, and an identification of the major replacement parts that shall be maintained in inventory for quick replacement.

   b. An identification of the source and air-cleaning device operating variables that shall be monitored to detect a malfunction or failure, the normal operating range of these variables, and a description of the method of monitoring or surveillance procedures.

   c. A description of the corrective procedures or operational changes that shall be taken in the event of a malfunction or failure to achieve compliance with the applicable emission limits.

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

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

V. TESTING/SAMPLING

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

1. The permittee shall assess opacity using USEPA Reference Method 9 - “Visual Determination of the Opacity of Emissions from Stationary Sources”, upon the request of AQD. **(R 336.1213(3))**

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

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall conduct and record non-certified visible emissions observations for the dust collectors servicing EUBOILER 1, EUBOILER2 (DC10) and EUBOILER3 (DC1) dumper houses and Coal Yard dust hopper DC(11) once per day when operating, as the primary indicator of the proper functioning of each fabric filter dust collector. If visible emissions are observed, the permittee shall document the visible emissions, including the duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each fabric filter dust collector is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

2. An excursion is the observation of visible emissions for the dust collectors serving EUBOILER1 and EUBOILER2 (DC10) or EUBOILER3 (DC1) dumper house or the coal yard dust hopper (DC11) for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

3. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or other measures as specified in the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. Any formal compliance determinations with the opacity limit established in 40 CFR 60.252(c) shall utilize Method 9 and the procedures in 40 CFR 60.11. **(40 CFR 60.254(b)(2))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report of monitoring deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

6. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

7. The permittee shall submit any performance test reports, except for Method 9, to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

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

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

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUSDA_U3
EMISSION UNIT CONDITIONS

DESCRIPTION

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

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Silos are controlled by bin vent filters.
Ball mills emissions controlled by spray scrubbers (mill scrubbers).
Recycle mix tank emissions controlled by a spray scrubber.

I. EMISSION LIMIT(S)

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

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

2. The permittee shall not operate EUSDA_U3 unless a malfunction abatement plan (MAP) as described in Rule 911(2), for operation of the process and emission control equipment, is implemented updated as necessary, and kept at the facility. If at any time the MAP fails to address or inadequately addresses an event that meets

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUSDA_U3 unless the associated enclosures, bin vent filters and spray scrubbers are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUSDA_U3 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

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

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

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

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

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

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall perform, and document non-certified visible emissions observations as required in SC I.1 and I.2 on a daily basis when EUSDA_U3 is operating. If during the observation there are any visible emissions detected from an emission point, then corrective procedures as defined in the MAP shall be implemented. Records of the non-certified visible emissions observations, USEPA Method 9 observations that are performed, the reason for any visible emissions observed, and any corrective actions taken, shall be kept on file and in a format acceptable to the AQD.[2] **(R 336.1301(1)(c)**

2. The permittee shall conduct and record non-certified visible emissions observations the Recycle Silo bin vent filters (SVRS-BV3A, SVRS-BV3B) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUSDA_U3. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. An excursion is the observation of visible emissions for a duration exceeding one (1) hour. **(40 CFR 64.6(c)(2))**

4. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or in accordance with the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

5. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

6. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

7. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and other information such as data used to document the adequacy of monitoring, or records of monitoring maintenance or corrective actions. **(40 CFR 64.9(b)(1))**

VII. REPORTING

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

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

2. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

3. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

4. Each semiannual report of monitoring and deviations shall include summary information on monitor downtime. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

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

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUDSI_U12
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

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

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUDSI_U12 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUDSI_U12 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUACI_U123
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

Bin vent filters

I. EMISSION LIMIT(S)

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

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

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUACI_U123 unless the associated enclosures and bin vent filters are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUACI_U123 as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

NA

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUBYPRODUCT
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Unit 3 System

- A large portion of PJFF flyash/byproduct is recycled back to the SDA via the SDA Recycle Flyash System and the remainder is conveyed to the Unit 3 Dry Flyash Byproduct System (for resale or landfill). The SDA Byproduct System consists of the following major equipment: two transfer towers [[TT3A and TT3B], three vacuum exhausters [two in operation and one spare], and three disposal silos [Flyash Silos A, B, and C]. Each transfer tower includes two filter separators (F/S) and a single transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter. TT3A, TT3B and the three associated vacuum exhausters located at Boiler 3 are regulated under EUBYPRODUCT.

- The vacuum conveyance system pulls flyash from the PJFF hoppers and transports the flyash in hard piping through a F/S and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster (two F/S's per transfer tank. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos A, B, or C where the material is loaded onto trucks for shipment as either byproduct or waste.

Unit 1 and 2 System

- The Dry Flyash Handling System services both Unit 1 and Unit 2 and consists of the following major equipment: three transfer towers [TT1, TT2 and TT3], five vacuum exhausters [three in operation and two spares], and two disposal silos [DSA, DSB]. Each transfer tower includes a filter separator and transfer tank. Each transfer tank and each disposal silo are equipped with a bin vent filter.

- TT1 and TT2 and the three associated vacuum exhausters located at Boiler 1&2 are regulated under EUBYPRODUCT. TT3 and the remaining two associated vacuum exhausters that solely support Unit 2 are not regulated by EUBYPRODUCT and are exempt from permitting under Michigan Rule 284(k).

- The vacuum conveyance system pulls flyash from each Boiler Unit's PJFF hoppers and transports the flyash in hard piping through a filter separator and into a transfer tank where the conveyance air is then discharged through a vacuum exhauster. The three vacuum exhausters that serve TT1 and TT2 normally discharge to the Unit 1 PJFF inlet ductwork. The two vacuum exhausters that serve TT3 can only discharge to the Unit 2 PJFF inlet duct. Transfer tank displacement air is released through a bin vent filter to atmosphere. Flyash and byproduct materials collected in the transfer tanks are periodically conveyed to disposal silos DSA and DSB where the material is loaded onto trucks for shipment as either byproduct or waste.

- When Boiler 1 and its associated PJFF are not in operation, then the vacuum exhausters associated with TT1 and TT2 will be redirected and one vacuum exhauster may intermittently discharge controlled emissions to atmosphere through a dedicated stack (bypassing the Boiler 1 PJFF). The operation of TT3 and its associated vacuum exhausters would remain unchanged; discharging into the Unit 2 inlet PJFF ductwork.

Common

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

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

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

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

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

I. EMISSION LIMIT(S)

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

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall not operate any portion of EUBYPRODUCT unless the associated enclosures and bin vent filters and filter separators are installed, maintained and operated in a satisfactory manner. Satisfactory manner includes operating and maintaining each control device in accordance with an approved MAP for EUBYPRODUCT as required in SC III.2.[2] **(R 336.1910, R 336.1911, R 336.2803, R 336.2804)**

2. The permittee shall not operate each byproduct transfer tank vacuum exhauster unless the associated filter separator exhaust gases discharge to an associated PJFF baghouse on either EUBOILER1, EUBOILER2, or EUBOILER3, except as allowed in SC IV.3.[2] **(R 336.1205, R 336.1331, R 336.2803, R 336.2804)**

3. The exhaust from the filter/separator associated with EUBOILER2 shall be routed back to the PJFF for EUBOILER1, except at times when the PJFF for EUBOILER1 is not operating.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d))**

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

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

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

2. The permittee shall conduct and record non-certified visible emissions observations from the bin vent filters servicing the EUBOILER3 Transfer Tanks (SVTT-BV3A, SVTT-BV3B) and the Landfill Silos (SVDCASS-BVA, SVDCASS-BVB, and SVCASSS-BVC) once per day when operating, as the primary indicator of the proper functioning of each bin vent filter for EUBYPRODUCT. If visible emissions are observed, the permittee shall document the visible emissions, including duration, and continue to observe the source of the visible emissions until no visible emissions are observed. The permittee shall initiate corrective actions as quickly as possible upon the detection of visible emissions. If there is a break in the visible emissions observations, it will be assumed that visible emissions continue to occur during any break in observations. The appropriate range of visible emissions defining proper functioning of each bin vent filter is no visible emissions. **(40 CFR 64.6(c)(1)(i), (ii), and (iii))**

3. The permittee shall utilize visible emissions as the primary indicator of the proper functioning of each PM control device. The appropriate range of visible emissions defining proper functioning of the PM Control Device is no visible emissions.[2] **(R 336.1201(3), 40 CFR 64.6(c)(1)(i) and (ii))**

4. The permittee shall keep, in a satisfactory manner, all records necessary to show that the Campbell Complex fugitive dust plan required by SC III.1 is being implemented.[2] **(R 336.1372, R 336.2803, R 336.2804, Act 451, Section 324.5524)**

5. The permittee shall keep, in a satisfactory manner, all records necessary to show that the MAP required by SC III.2 is being implemented.[2] **(R 336.1910, R 336.1911)**

6. The permittee shall keep, in a satisfactory manner, visible emissions records for the times that the filter/separator associated with EUBOILER2 is routed to SVTT12-FSVE instead of the PJFF for EUBOILER1.[2] **(R 336.1205, R 336.1331, 40 CFR 52.21(c) and (d), R 336.1213(3))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible in response to any noted exceedance or excursion. **(40 CFR 64.7(d))**

8. Upon detecting an excursion or exceedance, the owner or operator shall restore operation of the pollutant-specific emissions unit (including the control device and associated capture system) to its normal or usual manner of operation as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions or as specified by the MAP. The response shall include minimizing the period of any startup, shutdown or malfunction and taking any necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of an excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

9. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

10. The permittee shall properly maintain the monitoring system, including keeping necessary parts for routine repair of the monitoring equipment. **(40 CFR 64.7(b))**

11. The permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan and any activities undertaken to implement a quality improvement plan, and

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Each semiannual report of monitoring and deviations shall include summary information on the number, duration and cause of excursions and/or exceedances and the corrective actions taken. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

5. Each semiannual report shall include a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

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

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUAUXBLR12
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

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

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

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

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. To demonstrate continuous compliance, the permittee shall conduct a tune-up of the boiler every 5 years (within 61 months) of the date of the last tune up. If the boiler is not operating on the required date for tune-up, the tune-up must be conducted within 30 calendar days of startup.[2] **(40 CFR 63.7500(a), 40 CFR 63.7515(d), 40 CFR 63.7540(12) and (13))**

2. The permittee shall conduct tune up of the boiler as specified in the following:[2] **(40 CFR 63.7540(a)(12))**

   a. As applicable, inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next unit shutdown).

   b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern.

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next unit shutdown).

d. Optimize total emissions of CO.

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made.

f. Maintain on-site and submit, if requested by the Administrator, a report containing the information below:
   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen content in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater.
   ii. A description of any corrective actions taken as part of the tune-up.

3. At all times, the permittee must operate and maintain any affected source (as defined in 40 CFR 63.7490, stated in SC IX.1), including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.700(a)(3))**

4. Limited-use boilers and process heaters must complete a tune-up every 5 years as specified in 40 CFR 63.7540. They are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, the annual tune-up, or the energy assessment requirements in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. **(40 CFR 63.7500(c))**

5. The permittee shall install a fuel meter.[2] **(R 336.1201(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.5% by weight.[2] **(R 336.1201(3))**

2. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever a boiler is in use for 24 consecutive hours or more. **(R 336.1213(3))**

3. The permittee shall keep a record of the following on a monthly basis:[2] **(R 336.1201(3))**
   a. Total fuel usage
   b. Sulfur content of fuel oil
   c. Higher Heating Value of fuel oil

4. The permittee shall keep fuel use records for the days the boiler was operating.[2] **(40 CFR 63.7525(k))**

5. The permittee shall maintain a complete record of fuel oil specifications and/or fuel analysis for each delivery, or storage tank, of fuel oil used for the auxiliary boiler. These records may include purchase records for ASTM specification fuel oil, specifications or analyses provided by the vendor at the time of delivery, analytical results from laboratory testing, or any other records adequate to demonstrate compliance with the percent sulfur limit in fuel oil.[2] **(R 336.1201(3))**

6. The permittee shall keep records of compliance demonstrations.[2] **(R°336.1201(3))**

7. For each unit that meets the definition of limited-use boiler or process heater, the permittee must keep fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7525(k))**

8. The permittee must keep records according to paragraphs (a)(1) and (2) of 40 CFR 63.7555. **(40 CFR 63.7555(a))**
   a. A copy of each notification and report that is submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that permittee submitted, according to the requirements in 40 CFR Part 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**
   b. Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in 40 CFR Part 63.10(b)(2)(viii). **(40 CFR 63.7555(a)(2))**

9. For units in the limited use subcategory, the permittee must keep a copy of the federally enforceable permit that limits the annual capacity factor to less than or equal to 10 percent and fuel use records for the days the boiler or process heater was operating. **(40 CFR 63.7555(a)(3))**

10. Records must be in a form suitable and readily available for expeditious review, according to 40 CFR 63.10(b)(1). **(40 CFR 63.7560(a))**

11. As specified in 40 CFR 63.10(b)(1), the permittee must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. **(40 CFR 63.7560(b))**

12. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to 40 CFR 63.10(b)(1). The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**
4. The permittee must meet the notification requirements in 40 CFR 63.7545 according to the schedule in 40 CFR 63.7545 and in Subpart A of 40 CFR Part 63. **(40 CFR 63.7495(d))**

5. The permittee must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in 40 CFR 63.7545(e). **(40 CFR 63.7530(f))**

6. The permittee must submit to the Administrator all of the notifications in 40 CFR 63.7(b) and (c); 40 CFR 63.8(e), (f)(4) and (6); and 40 CFR 63.9(b) through (h) that apply by the dates specified. **(40 CFR 63.7545(a))**

7. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR Part 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550 as stated below. **(40 CFR 63.7550(b))**

a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual, biennial, and 5-year compliance reports must cover the applicable 1-, 2-, or 5-year periods from January 1 to December 31. **(40 CFR 63.7550(b)(3))**

b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. Annual, biennial, and 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

8. A compliance report must contain the information below depending on how the facility chooses to comply with the limits set in this rule. **(40 CFR 63.7550(c))**
   a. If the facility is subject to the requirements of a tune-up, permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv) and (xvii) of 40 CFR 63.7550, and paragraph (c)(5)(iv) of 40 CFR 63.7550 for limited-use boiler or process heater. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. The total operating time during the reporting period. **(40 CFR 63.7550(c)(5)(iv))**
      v. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12). Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      vi. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

9. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90-days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

1. 40 CFR Part 63, Subpart DDDDD applies to new or reconstructed affected sources as described in paragraph (a)(2) of 40 CFR 63.7490, as listed below. **(40 CFR 63.7490(a))**
   a. The affected source of 40 CFR Part 63, Subpart DDDDD is each new or reconstructed industrial, commercial, or institutional boiler or process heater, as defined in 40 CFR 63.7575, located at a major source. **(40 CFR 63.7490(a)(2))**

2. A boiler or process heater is:
   a. New if the permittee commences construction of the boiler or process heater after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commences construction. **(40 CFR 63.7490(b))**
   b. Reconstructed if the permittee meets the reconstruction criteria as defined in 40 CFR 63.2, the permittee commences reconstruction after June 4, 2010, and the permittee meets the applicability criteria at the time the permittee commence reconstruction. **(40 CFR 63.7490(c))**
3. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, you must complete the subsequent compliance demonstration no later than 180 days after the re-start of the affected source and according to the applicable provisions in 40 CFR 63.7(a)(2) as cited in Table 10 to 40 CFR Part 63, Subpart DDDDD. You must complete a subsequent tune-up by following the procedures described in 40 CFR 63.7540(a)(10)(i) through (vi) and within 30 calendar days of startup for units that are not operating at the time of their scheduled tune-up. **(40 CFR 63.7515(g))**

4. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 63.15 that apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

5. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subpart DDDDD)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCAT3DIESEL
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

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

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall install, maintain and operate EUCAT3DIESEL and after-treatment control device (if any) according to the manufacturer's emission-related written instructions or develop your own maintenance plan which must provide to the extent practicable for the maintenance and operation of the engine in a manner consistent with good air pollution control practice for minimizing emissions. **(40 CFR 63.6605, 40 CFR 63.6625(e))**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time EUCAT3DIESEL to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may operate EUCAT3DIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. EUCAT3DIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640(f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 63.6640(f)(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

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

V. TESTING/SAMPLING

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

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

See Appendix 3-C

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. The permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. The permittee shall keep in a satisfactory manner, records to demonstrate continuous compliance with the operating limitations. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6660)**

4. The permittee shall keep in a satisfactory manner, records of the maintenance conducted to demonstrate that the engine and after-treatment control device (if any) were operated and maintained according to the developed maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(e), 40 CFR 63.6660)**

5. The permittee shall monitor and record the total hours of operation for EUCAT3DIESEL per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

6. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

7. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

8. The permittee shall maintain a record of the applicability determination for each Reciprocating Internal Combustion Engine (RICE) relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

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

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

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

6. For any engine that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h): **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.

ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

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

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUCATDIESEL12
EMISSION UNIT CONDITIONS

DESCRIPTION

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

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period / Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NMHC + NOx	6.4 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
2. CO	3.5 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**
3. PM	0.20 g/kW-hr[2]	Hourly	EUCATDIESEL12	SC V.1 SC VI.2	**40 CFR 60.4205(b)**

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall not operate EUCATDIESEL12 for more than 500 hours per year on a 12-month rolling time period basis as determined at the end of each calendar month. The 500 hours includes the 100 hours for the purpose of necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(3), R 336.1225, R 336.1702(a), R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d))**

2. The permittee may operate EUCATDIESEL12 for no more than 100 hours per calendar year, as determined at the end of each calendar month, for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUCATDIESEL12 may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing. The 50 hours per calendar year for non-emergency situations may not be used for peak shaving or to generate income for a facility to supply non-emergency power as part of a financial arrangement with another entity.[2] **(40 CFR 60.4211(f), 40 CFR 63.6640(f)**

3. The permittee shall install, maintain, and operate EUCATDIESEL12 according to the manufacturer emissions-related written instructions, or procedures developed by the owner/operator and approved by the engine manufacturer, over the entire life of the engine.[2] **(R 336.1205(3), R 336.1225, R 336.1911, R 336.2803, R 336.2804, 40 CFR 52.21(c) & (d), 40 CFR 60.4206, 40 CFR 60.4211)**

4. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4211(f)(1), 40 CFR 63.6640(f)(1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUCATDIESEL12 with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(3), R 336.1225, 40 CFR 60.4209(a), 40 CFR 63.6625(f))**

2. The nameplate capacity of EUCATDIESEL12 shall not exceed 2,000 kW, as certified by the equipment manufacturer.[2] **(R 336.1205(3))**

V. TESTING/SAMPLING

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

1. The permittee shall conduct an initial performance test for EUCATDIESEL12 within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4205 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart IIII. If a performance test is required, the performance tests shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4212. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4211)**

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the last day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 52.21 (c) & (d))**

2. The permittee shall keep, in a satisfactory manner, a record of testing required in SC V.1 or manufacturer certification documentation indicating that EUCATDIESEL12 meets the applicable emission limitations contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211)**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUCATDIESEL12, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUCATDIESEL12, including what classified the operation as emergency and how many hours are spent for maintenance or readiness testing and non-emergency operation.[2] **(R 336.1205(3), R 336.2803, R 336.2804, 40 CFR 60.4211(f), 40 CFR 60.4214(b))**

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

See Appendix 3-C

VII. REPORTING

1. The permittee shall submit all applicable notifications specified in 40 CFR 63.7(b) and (c), 40 CFR 63.8 (e), (f)(4), and (f)(6), and 40 CFR 63.9(b) through (e), (g), and (h) by the dates specified.[2] **(40 CFR 63.6645(a)(3) and (f))**

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

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

4. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

5. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

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

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and IIII, as they apply to EUCATDIESEL12.[2] **(40 CFR Part 60, Subparts A & IIII,)**

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUCATDIESEL12 upon startup.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

EUGUARDSHK_ENG
EMISSION UNIT CONDITIONS

DESCRIPTION

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

Flexible Group ID: NA

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. NOx + Hc	10 g/kW-hr g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**
2. 2. CO	387 g/hp-hr	Hourly	EUGUARDSHK_ENG	SC VI.2	**40 CFR 60.6233(d)**

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 60.4243(d)(1))**

2. The permittee may operate EUGUARDSHK_ENG for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 60.4243(d)(2), 40 CFR 63.6640(f))**

3. EUGUARDSHK_ENG may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 60.4243(d)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for the permittee to supply non-emergency power as part of a financial arrangement with another entity. **(40 CFR 60.4243(d)(3), 40 CFR 63.6640(f))**

4. The permittee shall operate and maintain EUGUARDSHK_ENG such that it meets the emission limits in SC I.1, and I.2 over the entire life of the engine. **(40 CFR 60.4234, 40 CFR 60.4243(b))**

5. If the permittee purchased a certified engine, according to procedures specified in 40 CFR Part 60, Subpart JJJJ, for the same model year, the permittee shall meet the following requirements for EUGUARDSHK_ENG:

   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;

b. Keep a maintenance plan and the permittee may only change those engine settings that are permitted by the manufacturer. If you do not operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine; and

c. Meet the requirements as specified in 40 CFR Part 1068, Subparts A through D.

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

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. EUGUARDSHK_ENG shall be certified to meet the applicable emission standard of 40 CFR 60.4233. The permittee shall install and configure each engine according to the manufacturer's specifications. **(40 CFR 60.4243)**

2. The permittee shall equip and maintain EUGUARDSHK_ENG with non-resettable hours meters to track the operating hours. **(40 CFR 60.4237, 40 CFR 63.6655(f))**

3. The nameplate capacity of EUGUARDSHK_ENG shall not exceed 500 BHP, as certified by the equipment manufacturer. **(40 CFR 63.6590(c)(4))**

V. TESTING/SAMPLING

1. The permittee shall conduct an initial performance test for EUGUARDSHK_ENG within one year after startup of the engine to demonstrate compliance with the emission limits in 40 CFR 60.4231 unless the engine has been certified by the manufacturer and the permittee maintains the engine as required by 40 CFR Part 60, Subpart JJJJ. If a performance test is required, the performance test shall be conducted at the owner's expense, in accordance with Department requirements and according to 40 CFR 60.4244. No less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing, including any modifications to the method in the test protocol that are proposed after initial submittal. The permittee must submit a complete report of the test results to the AQD Technical Programs Unit and District Office within 60 days following the last date of the test.[2] **(40 CFR 60.4244)**

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

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall keep in a satisfactory manner, records of all maintenance conducted on EUGUARDSHK_ENG. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 60.4245(a)(2))**

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

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

See Appendix 4

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the provisions of the federal Standards of Performance for New Stationary Sources as specified in 40 CFR Part 60, Subparts A and JJJJ, as they apply to EUGUARDSHK_ENG. **(40 CFR Part 60, Subparts A and JJJJ)**

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

D. FLEXIBLE GROUP SPECIAL CONDITIONS

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

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

FLEXIBLE GROUP SUMMARY TABLE

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

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

FGBOILER12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

Emission Units: EUBOILER1, EUBOILER2

POLLUTION CONTROL EQUIPMENT

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

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

NA

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

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

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

See Appendices 3-A and 5

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall utilize COMS-recorded opacity as an indicator of the emission unit's compliance with the particulate matter limit, except during periods of monitoring and system malfunction, system repairs or QA/QC activities. The appropriate range of opacity defining proper function of the PJFF is 0-20% opacity. An excursion is defined as any two (2) or more consecutive 1-hour block average opacity values greater than 15%. **(40 CFR 64.6(c)(1)(i) and (ii))**

2. The permittee shall continuously monitor and record any alarms and corrective actions taken. **(40 CFR 64.6(c)(1)(i) and (ii))**

3. The permittee shall properly maintain the COMS, including completing daily COMS zero and calibration tests; conduct necessary preventative maintenance; maintaining necessary parts for routine repairs of the monitoring equipment; and demonstrating adequate performance through an annual monitor audit. **(40 CFR 64.6(c)(1)(iii), 40 CFR 64.7(b))**

4. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the owner or operator shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. The permittee shall operate the COMS during all required periods when the coal-fired boiler is operating. Data recorded during monitoring malfunctions, repair activities and QA/QC operations shall not be used for 40 CFR Part 64 compliance. **(40 CFR 64.6(c)(3), 40 CFR 64.7(c))**

5. The permittee shall conduct all required monitoring per the CAM Plan and otherwise satisfy the requirements specified in 40 CFR 64.7 through 40 CFR 64.9. **(40 CFR 64.6(c)(3), 40 CFR 64.7(a))**

6. The required COMS shall collect data for all required intervals when the emission unit is operating. **(40 CFR 64.7(c)(1)(iii))**

7. The permittee shall restore operation of the emission unit, control device, and associated pollutant capture system equipment to normal/compliant operation as quickly as possible, in accordance with good air pollution control practices for minimizing emissions in response to any noted exceedance or excursion. Excursions shall trigger an internal investigation, corrective action(s) per the MAP, and a CAM excursion summary reporting requirement. Necessary response shall include minimizing the period of any startup, shutdown or malfunction and taking necessary corrective actions to restore normal operation and prevent the likely recurrence of the cause of the excursion or exceedance (other than those caused by excused startup or shutdown conditions). **(40 CFR 64.7(d))**

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

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

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

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

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

6. Each semiannual report of monitoring deviations shall include summary information on the number, duration, and cause of exceedances/excursions in the reporting period; and the corrective actions taken in response. If there were no excursions and/or exceedances in the reporting period, then this report shall include a statement that there were no excursions and/or exceedances. **(40 CFR 64.9(a)(2)(i))**

7. Each semiannual report of monitoring deviations shall include summary information on monitor downtime in the reporting period. If there were no periods of monitor downtime in the reporting period, then this report shall include a statement that there were no periods of monitor downtime. **(40 CFR 64.9(a)(2)(ii))**

8. Each semiannual report of monitoring deviations shall include a description of the actions taken to implement a Quality Improvement Plan (QIP) during the reporting period, if appropriate. If a QIP has been completed, the report shall include documentation that the QIP has been implemented, and a discussion pertaining to whether the QIP implementation has reduced the likelihood of excursions or exceedances. **(40 CFR 64.9(a)(2)(iii))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

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

Footnotes:
[1]This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2]This condition is federally enforceable and was established pursuant to Rule 201(1)(a).
[3]This condition is federally enforceable and was originally established in the consent decree settling, "U.S. V CONSUMERS ENERGY COMPANY, CIVIL ACTION 14-13580, E.D. MICH., 2014" and also pursuant to Act 451, Section 324.5503(b), and will remain in effect after termination of the consent decree.
[4]Definitions specific to this condition may be found in Appendix 1-B: Definitions Applicable to Specified Permit Conditions.

FGMATS_U12
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

Emission Units: EUBOILER1 and EUBOILER2

POLLUTION CONTROL EQUIPMENT

EUBOILER1:
Low-NOx burners,
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

EUBOILER2:
Low-NOx burners,
Selective catalytic reduction (SCR),
Sorbent injection (ACI) (activated carbon or other sorbent) for mercury control,
Dry sorbent injection (DSI) (hydrated lime or other sorbent) for acid gas control,
Pulse-jet fabric filter (PJFF) baghouse for PM control.

I. EMISSION LIMIT(S)

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

* The emission limits apply at all times except during startup and shutdown.
+ If the unit(s) no longer meets the requirement for LEE status, the unit(s) will comply by stack testing quarterly until a continuous monitoring system has been installed, certified, and is operating.

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee shall conduct a tune-up of each emission unit of FGMATS_U12 burner(s) and combustion controls, as applicable, at least every 36 calendar months, or each 48 calendar months if neural network combustion optimization software is employed, as specified in 40 CFR 63.10021(e). **(40 CFR 63.10000(e), 40 CFR 63.10006(i), 40 CFR 63.10021(e))**

2. For the startup of any emission unit of FGMATS_U12 which will comply using paragraph (1) of the definition of ''startup'' in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U12 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U12 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U12 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U12 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3, 40 CFR 63.10022(a)(4))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

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

V. TESTING/SAMPLING

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

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

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

3. If the permittee uses the provisions for LEE status for any pollutant except for Hg, the permittee shall verify each LEE pollutant emission rate from the applicable emission unit(s) of FGMATS_U12 by testing at owner's expense, in accordance with 40 CFR 63.10007 and Table 5 to 40 CFR Part 63, Subpart UUUUU. The permittee must complete the test once every 36 months and at least 1,050 days since the previous performance test to demonstrate continued LEE status. If a performance test deadline is missed due to the EGU being inoperative and 168 or more boiler operating hours occur in the next test period, an additional performance test shall be completed in the next test period, with at least 350 calendar days separating the performance tests conducted in the same 3-year period. **(40 CFR 63.10006(b), 40 CFR 63.10006(f), 40 CFR 63.10007, 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. Unless an alternate schedule has been approved by the AQD, no less than 30 days prior to testing, the permittee shall submit a complete test plan to the AQD Technical Programs Unit and District Office. The AQD must approve the final plan prior to testing. The protocol shall describe the test method(s) and the maximum routine operating conditions, including targets for key operational parameters associated with air pollution control equipment to be monitored and recorded during testing, as applicable. **(40 CFR 63.7, 40 CFR 63.10007, 40 CFR 63.10030(a))**

VI. MONITORING/RECORDKEEPING

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

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

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. For any emission unit not relying on the LEE provisions for Hg, the permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

4. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative

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

5. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit **OR** (30-day (or 90-day if emission averaging (as applicable)) rolling weighted average Hg emission rate records for the combination of units participating in an averaging plan) excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

6. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

7. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

8. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

9. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

10. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

d. For each emission unit subject to an emission limit:

i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

iii. For an emission unit that qualifies as a LEE under 40 CFR 63.10005(h), the permittee shall keep annual records that document that the emissions in the previous stack test(s) continue to qualify the unit for LEE status for an applicable pollutant, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the pollutant to increase within the past year. **(40 CFR 63.10032(d)(3))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ‘‘startup’’ in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

h. If the permittee elects to average emissions consistent with 40 CFR 63.10009, the permittee shall keep a copy of the emissions averaging implementation plan required in 40 CFR 63.10009(g), all calculations required under 40 CFR 63.10009, including daily records of heat input or steam generation, as applicable, and monitoring records consistent with 40 CFR 63.10022. **(40 CFR 63.10032(e))**

11. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

12. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

   a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

   b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

   c. Indicate whether any emission unit in FGMATS_U12 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

   d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

   e. Report emergency bypass information annually from units with LEE status. **(40 CFR 63.10031(c)(6))**

   f. A summary of the results of the annual performance tests and documentation of any operating limits that were reestablished during the test, if applicable. If the permittee is conducting stack tests once every 3 years to maintain LEE status, consistent with 40 CFR 63.10006(b), the report shall include the date of each stack test conducted during the previous 3 years, a comparison of emission level the permittee achieved in each stack test conducted during the previous 3 years to the 50% emission limit threshold required in 40 CFR 63.10005(h)(1)(i), and a statement as to whether there have been any operational changes since the last stack test that could increase emissions. **(40 CFR 63.10031(c)(7))**

   g. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U12 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U12, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period. **(40 CFR Part 63, Subpart UUUUU, Table 8)**

   h. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

   i. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial

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

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, within 60 days after the date of completing each CEMS (SO2, PM, HCl, HF, and Hg) performance evaluation test, as defined in 40 CFR 63.2, the permittee must submit the relative accuracy test audit (RATA) data (or, for PM CEMS, RCA and RRA data) required by this subpart to USEPA's WebFIRE database by using CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The RATA data shall be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (http://www.epa.gov/ttn/chief/ert/index.html). Only RATA data compounds listed on the ERT Web site are subject to this requirement. At the discretion of the AQD, the permittee must also submit these RATA reports to the AQD District Supervisor in a format approved by the AQD. Owners or operators shall submit calibration error testing, drift checks, and other information required in the performance evaluation as described in 40 CFR 63.2 and as required in this chapter. **(40 CFR 63.10031(f)(1))**

8. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

9. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

10. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

11. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, VII.8 and VII.10 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

12. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already

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

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).
   a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:
      i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**
      ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**
      iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**
      iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**
      v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**
   b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**
   c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the site-specific monitoring plan. The monitoring plan must address the following provisions: **(40 CFR 63.10000(d), 40 CFR 63.10010)**
   a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If the permittee chooses to reapply for LEE status, the permittee must demonstrate all performance tests and CEMS or sorbent trap monitoring system data over a consecutive 3-year period show compliance with the LEE criteria. **(40 CFR 63.10006(b)(2) and (h))**

4. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

5. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGMATS_U3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

Emission Unit: EUBOILER3

POLLUTION CONTROL EQUIPMENT

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

I. EMISSION LIMIT(S)

Pollutant	Limit	Time Period/ Operating Scenario	Equipment	Monitoring/ Testing Method	Underlying Applicable Requirements
1. Filterable PM	0.030 lb/MMBTU*	30-day boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.3 SC VI.7 SC VI.8	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.a**
2. SO_2	0.20 lb/MMBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC VI.2 SC VI.6 SC VI.7 SC VI.10 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.b**
3. Mercury (Hg)	1.2 lb/TBTU*	30-boiler operating day rolling arithmetic average updated at the end of each new boiler operating day	EUBOILER3	SC V.1 SC VI.4 SC VI.7 SC VI.9 SC VI.14	**40 CFR 63.9991 40 CFR Part 63, Subpart UUUUU, Table 2.1.c**

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

II. MATERIAL LIMIT(S)

NA

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

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

2. For the startup of any emission unit of FGMATS_U3 which will comply using paragraph (1) of the definition of ‘‘startup’’ in 40 CFR 63.10042, the permittee must use clean fuels as defined in 40 CFR 63.10042 for ignition. Once the emission unit(s) of FGMATS_U3 convert(s) to firing coal, residual oil, or solid oil-derived fuel, the permittee must engage all the applicable control technologies except dry scrubber and SCR. The permittee must start the dry scrubber and SCR systems, if present, appropriately to comply with relevant standards applicable during normal operation. The permittee must comply with all applicable emission limits at all times except for periods that meet the applicable definitions of startup and shutdown in 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

3. During shutdown of any emission unit of FGMATS_U3 while firing coal, residual oil, or solid oil-derived fuel, the permittee must vent emissions to the main stack(s) and operate all applicable control devices and continue to operate those control devices after the cessation of coal, residual oil, or solid oil-derived fuel being fed into the applicable emission unit(s) of FGMATS_U3 and for as long as possible thereafter considering operational and safety concerns. In any case, the permittee must operate their controls when necessary to comply with other standards made applicable to the FGMATS_U3 by a permit limit or a rule other than 40 CFR Part 63, Subpart UUUUU and that require operation of the control devices. If, in addition to the fuel used prior to initiation of shutdown, another fuel must be used to support the shutdown process, that additional fuel must be one or a combination of the clean fuels defined in 40 CFR 63.10042 and must be used to the maximum extent possible taking into account considerations such as not compromising boiler or control device integrity. **(40 CFR 63.10042, 40 CFR Part 63, Subpart UUUUU, Table 3)**

4. The emission limits and operating limits in 40 CFR Part 63, Subpart UUUUU apply at all times except during periods of startup and shutdown; however, the applicable work practice requirements, which are specified in items 3 and 4 of Table 3 of 40 CFR Part 63, Subpart UUUUU must be met during periods of startup or shutdown. **(40 CFR 63.10000(a), 40 CFR Part 63, Subpart UUUUU, Table 3)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

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

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

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

2. The permittee must operate all CMS during shutdown. The permittee must also collect appropriate data, and the permittee must calculate the pollutant emission rate for each hour of shutdown for those pollutants for which a CMS is used. The permittee must collect monitoring data during shutdown periods, as specified in 40 CFR 63.10020(a). The permittee must keep records during shutdown periods, as provided in 40 CFR 63.10032 and 40 CFR 63.10021(h). Any fraction of an hour in which shutdown occurs constitutes a full hour of shutdown. **(40 CFR Part 63, Subpart UUUUU, Table 3)**

3. The permittee shall install, calibrate, maintain and operate a device to monitor and record the PM concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate the PM CEMS to meet the timelines, requirements and reporting detailed in Performance Specification 11 in 40 CFR Part 60, Appendix B and Procedure 2 in 40 CFR Part 60, Appendix F. **(40 CFR 63.10010(i), 40 CFR Part 63, Subpart UUUUU, Table 5)**

4. The permittee shall install, calibrate, maintain and operate a device to monitor and record the Hg concentration from each emission unit on a continuous basis. The permittee shall install and operate the Hg CEMS or sorbent trap monitoring system to meet the timelines, requirements and reporting detailed in Appendix A of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(c)(1)(vi))**

5. The permittee shall install, maintain, and operate a device(s) to monitor and record the SO_2 concentration of the exhaust gas from each emission unit on a continuous basis. The permittee shall install and operate each CEMS to meet the timelines, requirements and reporting detailed in 40 CFR Part 75, Appendices A and B. **(40 CFR 63.10000(c)(1)(v))**

6. If required to convert measured pollutant concentrations to the units of the applicable mass per heat input emission limit(s) or for routine operation of a sorbent trap monitoring system, the permittee shall install, calibrate, maintain and operate a device to monitor and record the oxygen (O_2) or carbon dioxide (CO_2) exhaust gas content, exhaust gas flow rate and/or moisture from each emission unit on a continuous basis. The monitor shall be operated in accordance with procedures outlined in 40 CFR Part 75, Appendices A and B. As an alternative to moisture monitoring, the permittee may elect to use appropriate fuel-specific default moisture values from 40 CFR 75.11(b) for coal-fired units or a default moisture value for non-coal-fired units as established via petition to the Administrator under 40 CFR 75.66. **(40 CFR 63.10010(b)-(d), 40 CFR Part 63, Subpart UUUUU, Table 5)**

7. If the permittee elects to use a PM CEMS or participate in an averaging plan for PM, total non-Hg HAP metals, or individual metals, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average PM, total non-Hg HAP metals, or individual metals (as applicable) emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

8. For any emission unit not relying on the LEE provisions for Hg, the permittee shall keep, in a satisfactory manner, hourly (if applicable) and 30-day rolling average Hg emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

9. The permittee shall keep, in a satisfactory manner, hourly and 30-day rolling average SO_2 emission rate records for each emission unit excluding periods of startup and shutdown. **(40 CFR 63.10010, 40 CFR 63.10021, 40 CFR Part 63, Subpart UUUUU, Table 7)**

10. The permittee must operate the required monitoring system(s) and collect data at all required intervals at all times that the affected EGU is operating, except for periods of monitoring system malfunctions or out-of-control periods (see 40 CFR 63.8(c)(7) of 40 CFR Part 63, Subpart A), and required monitoring system quality assurance or quality control activities, including, as applicable, calibration checks and required zero and span adjustments. The permittee is required to affect monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable. **(40 CFR 63.10020(b))**

11. The permittee may not use data recorded during startup or shutdown in calculations used to report emissions, except as otherwise provided in 40 CFR 63.10000(c)(1)(vi)(B) and 40 CFR 63.10005(a)(2)(iii). In addition, data recorded during monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods or required monitoring system quality assurance or control activities may not be used in calculations used to report emissions or operating levels. The permittee must use all of the quality-assured data collected during all other periods in assessing the operation of the control device and associated control system. **(40 CFR 63.10020(c))**

12. Failure to collect required data is a deviation from the monitoring requirements except for periods of monitoring system malfunctions or monitoring system out-of-control periods, repairs associated with monitoring system malfunctions or monitoring system out-of-control periods and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. **(40 CFR 63.10020(d))**

13. If the permittee uses CEMS to measure SO_2, PM, HCl, HF, or Hg emissions (or sorbent trap monitoring system), except as otherwise provided in 40 CFR 63.10020(c), the permittee must demonstrate continuous compliance by using all quality-assured hourly data recorded by the CEMS (or sorbent trap monitoring system) and other required monitoring systems to calculate the arithmetic average emissions rate in units of the standard on a continuous 30-boiler operating day (or, if alternate emissions averaging is used for Hg, a 90-boiler operating day) rolling average basis, updated at the end of each new boiler operating day. Use Equation 8 in 40 CFR 63.10021(b) to determine the 30- or 90-boiler operating day rolling average. **(40 CFR 63.10021(a) and (b))**

14. The permittee must keep the following records:

    a. A copy of each notification and report that has been submitted to comply with 40 CFR Part 63, Subpart UUUUU, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that has been submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.10032(a)(1))**

    b. Records of performance stack tests, fuel analyses, or other compliance demonstrations and performance evaluations, as required in 40 CFR 63.10(b)(2)(viii). **(40 CFR 63.10032(a)(2))**

    c. For each CEMS and CPMS, the permittee must keep the following records:

        i. Records described in 40 CFR 63.10(b)(2)(vi) through (xi). **(40 CFR 63.10032(b)(1))**

        ii. Previous (i.e., superseded) versions of the performance evaluation plan as required in 40 CFR 63.8(d)(3). **(40 CFR 63.10032(b)(2))**

        iii. Request for alternatives to relative accuracy test for CEMS as required in 40 CFR 63.8(f)(6)(i). **(40 CFR 63.10032(b)(3))**

        iv. The date and time that each deviation started and stopped and whether the deviation occurred during a period of startup, shutdown, or malfunction or during another period. **(40 CFR 63.10032(b)(4))**

        v. If the permittee continuously monitors Hg and/or HCl and/or HF emissions, the permittee must also keep the records required under Appendix A and/or Appendix B of 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10032(a))**

    d. For each emission unit subject to an emission limit:

        i. The permittee shall keep the monthly fuel use by each emission unit, including the type(s) of fuel and amount(s) used. **(40 CFR 63.10032(d)(1))**

        ii. If the permittee combusts non-hazardous secondary materials that have been determined not to be solid waste pursuant to 40 CFR 241.3(b)(1), the permittee must keep a record which documents how the secondary material meets each of the legitimacy criteria. If the permittee combusts a fuel that has been processed from a discarded non-hazardous secondary material pursuant to 40 CFR 241.3(b)(2), the permittee must keep records as to how the operations that produced the fuel satisfies the definition of processing in 40 CFR 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under 40 CFR 241.3(c), the permittee must keep a record which documents how the fuel satisfies the requirements of the petition process. **(40 CFR 63.10032(d)(2))**

e. Regarding startup periods or shutdown periods:

i. If the permittee chooses to rely on paragraph (1) of the definition of ‘‘startup’’ in 40 CFR 63.10042 for the emission unit(s), the permittee shall keep records of the occurrence and duration of each startup or shutdown. **(40 CFR 63.10032(f)(1))**

ii. The type(s) and amount(s) of fuel used during each startup or shutdown. **(40 CFR 63.10032(i))**

f. The occurrence and duration of each malfunction of an operation (i.e., process equipment) or the air pollution control and monitoring equipment. **(40 CFR 63.10032(g))**

g. Actions taken during periods of malfunction to minimize emissions in accordance with 40 CFR 63.10000(b), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. **(40 CFR 63.10032(h))**

15. The permittee shall keep all records in a form suitable and readily available for expeditious review and for at least 5 years after the date of each occurrence, corrective action, report, or record. The records must be kept onsite for at least 2 years and may be kept offsite for the remaining 3 years. **(40 CFR 63.10(b)(1), 40 CFR 63.10033)**

16. The permittee shall maintain on site and submit, if requested by the Administrator, an annual report of periodic performance tune-ups containing the information required by 40 CFR 63.10021(e)(8). The reports shall be in a format acceptable to the Administrator. If requested by the AQD District Supervisor, the permittee shall also submit an annual report with the results of the performance tune-ups. **(40 CFR 63.10021(e)(8))**

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. Semiannual reporting of the information required in 40 CFR 63.10031(c)(1) through (9), (d), and (e) as applicable. The report shall be postmarked or received by the Administrator by March 15 for reporting period July 1 to December 31 and September 15 for reporting period January 1 to June 30. The report shall include the following:

a. The information required by the Continuous Monitoring Summary Report located in 40 CFR 63.10(e)(3)(vi). **(40 CFR 63.10031(c)(1))**

b. The total fuel use by each affected source subject to an emission limit, for each calendar month within the semiannual reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by USEPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure. **(40 CFR 63.10031(c)(2))**

c. Indicate whether any emission unit in FGMATS_U3 burned new types of fuel during the reporting period. If new types of fuel were burned, include the date of the performance test where that fuel was in use. **(40 CFR 63.10031(c)(3))**

d. Include the date of the most recent tune-up for each emission unit. The date of the tune-up is the date the tune-up provisions specified in 40 CFR 63.10021(e)(6) and (7) were completed. **(40 CFR 63.10031(c)(4))**

e. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to FGMATS_U3 and there are no deviations from the requirements for work practice standards in Table 3 to 40 CFR Part 63, Subpart UUUUU that apply to FGMATS_U3, the report shall include a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, and operating parameter monitoring systems, were out-of-control as specified in 40 CFR 63.8(c)(7), a statement

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

f. If there is a deviation from any emission limitation (emission limit and operating limit) or work practice standard during the reporting period, the report must contain a brief description of the deviation, the duration of the deviation, the cause of the deviation, and the information in 40 CFR 63.10031(d). If there were periods during which the CMS's, including continuous emissions monitoring systems and continuous parameter monitoring systems, were out-of-control, as specified in 40 CFR 63.8(c)(7), the report must contain the information in 40 CFR 63.10031(e). **(40 CFR 63.10031(c)(1) through (9), (d), and (e), 40 CFR 63.10031(a), 40 CFR 63.10031(c)(9), 40 CFR Part 63, Subpart UUUUU, Table 8)**

g. If the affected source submits a compliance report pursuant to Table 8 in 40 CFR Part 63, Subpart UUUUU, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in 40 CFR Part 63, Subpart UUUUU, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report required by SC VII.2. **(40 CFR 63.10031(e))**

5. The permittee must submit any of the following applicable notifications by the dates specified within the specific citation: 40 CFR 63.7(b) and (c) Notification of performance test and Quality assurance program; 40 CFR 63.8(e) Performance evaluation of continuous monitoring systems; 40 CFR 63.8(f)(4) Request to use alternative monitoring methods; 40 CFR 63.8(f)(6) Alternative to the relative accuracy test; 40 CFR 63.9(b) Initial notifications; 40 CFR 63.9(c) Request for extension of compliance; 40 CFR 63.9(d) Notification that source is subject to special compliance requirements; 40 CFR 63.9(e) Notification of performance test, which shall be submitted at least 30 days before the performance test is scheduled to begin; 40 CFR 63.9(f) Notification of opacity and visible emission observations; 40 CFR 63.9(g) Additional notification requirements for sources with continuous monitoring systems; and 40 CFR 63.9(h) Notification of compliance status. **(40 CFR 63.10030(a))**

6. On or after July 1, 2020, within 60 days after the date of completing each performance test, the permittee must submit the performance test reports required by this subpart to USEPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). Performance test data must be submitted in the file format generated through use of USEPA's Electronic Reporting Tool (ERT) (see http://www.epa.gov/ttn/chief/ert/index.html). Only data collected using those test methods on the ERT Web site are subject to this requirement for submitting reports electronically to WebFIRE. At the discretion of the AQD, the permittee must also submit these reports, one to the Technical Programs Unit Supervisor and one to the AQD District Supervisor, in a format approved by the AQD. **(40 CFR 63.10031(f))**

7. On or after July 1, 2020, for a PM CEMS, PM CPMS, or approved alternative monitoring using a HAP metals CEMS, within 60 days after the reporting periods ending on March 31, June 30, September 30, and December 31, the permittee must submit quarterly reports to USEPA's WebFIRE database by using the CEDRI that is accessed through USEPA's CDX (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. For each reporting period, the quarterly reports must include all of the calculated 30-boiler operating day rolling average values derived from the CEMS and PM CPMS. **(40 CFR 63.10031(f)(2))**

8. Reports for a SO_2 CEMS, a Hg CEMS or sorbent trap monitoring system, a HCl or HF CEMS, and any supporting monitors for such systems (such as a diluent or moisture monitor) shall be submitted using the ECMPS Client Tool, as provided for in 40 CFR Part 63, Subpart UUUUU, Appendices A and B and 40 CFR 63.10021(f). **(40 CFR 63.10031(f)(3))**

9. On or after July 1, 2020, the permittee must submit all reports required by 40 CFR 63.10031 (c) and (d) electronically using CEDRI that is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The permittee must use the appropriate electronic reporting form in CEDRI or provide an alternate electronic file consistent with USEPA's reporting form output format. If requested by the AQD, the permittee must also submit these reports, to the AQD District Supervisor in a format approved by the AQD. **(40 CFR 63.10031(f)(4))**

10. Prior to July 1, 2020, all reports subject to electronic submittal in SC VII.6, VII.7, and VII.9 shall be submitted to the USEPA at the frequency specified in those paragraphs in electronic portable document format (PDF) using the ECMPS Client Tool. Each PDF version of a submitted report must include sufficient information to assess compliance and to demonstrate that the testing was done properly. The data elements listed at 40 CFR 63.10031(f)(6)(i)-(xii) must be entered into the ECMPS Client Tool at the time of submission of each PDF file. **(40 CFR 63.10031(f)(6))**

11. If requested by the Administrator, the permittee must submit the monitoring plan (or relevant portion of the plan) at least 60 days before the initial performance evaluation of a particular CMS, except where the CMS has already undergone a performance evaluation that meets the requirements of 40 CFR 63.10010 (e.g., if the CMS was previously certified under another program). **(40 CFR 63.10000(d)(3))**

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. For each emission unit or emissions averaging group complying with an emission limit as specified in Table 2 of 40 CFR Part 63, Subpart UUUUU, the permittee may request to switch from a mass per heat input to a mass per gross output limit (or vice versa).

    a. The permittee may switch from a mass per heat input to a mass per gross output limit (or vice-versa), provided that:

        i. The permittee submits a request that identifies for each emission unit or emissions averaging group involved in the proposed switch both the current and proposed emission limit. **(40 CFR 63.10030(e)(7)(iii)(A)(1))**

        ii. The request arrives to the Administrator at least 30 calendar days prior to the date that the switch is proposed to occur. **(40 CFR 63.10030(e)(7)(iii)(A)(2))**

        iii. The request demonstrates through performance stack test results completed within 30 days prior to the submission, compliance for each emission unit or emissions averaging group with both the mass per heat input and mass per gross output limits. **(40 CFR 63.10030(e)(7)(iii)(A)(3))**

        iv. The permittee revises and submits all other applicable plans, e.g., monitoring and emissions averaging, with the request. **(40 CFR 63.10030(e)(7)(iii)(A)(4))**

        v. The permittee maintains records of all information regarding the choice of emission limits. **(40 CFR 63.10030(e)(7)(iii)(A)(5))**

    b. The permittee may begin to use the revised emission limits starting in the next reporting period, after receipt of written acknowledgement from the Administrator of the switch. **(40 CFR 63.10030(e)(7)(iii)(B))**

    c. From the submission of the request until start of the next reporting period after receipt of written acknowledgement from the Administrator of the switch, the permittee shall demonstrate compliance with both the mass per heat input and mass per gross output emission limits for each pollutant for each emission unit or emissions averaging group. **(40 CFR 63.10030(e)(7)(iii)(C))**

2. If using a CMS to demonstrate continuous compliance with an emission limit or operating limit, the permittee must develop a site-specific monitoring plan and submit this site-specific monitoring plan, if requested, at least 60 days before the initial performance evaluation (where applicable) of the CMS. This requirement also applies to the permittee if the permittee petitions the Administrator for alternative monitoring parameters under 40 CFR 63.8(f). This requirement to develop and submit a site-specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and CPMS prepared under Appendix B of 40 CFR Part 60 or 40 CFR Part 75, and that meet the requirements of 40 CFR 63.10010. Using the process described in 40 CFR 63.8(f)(4), the permittee may request approval of monitoring system quality assurance and quality control procedures alternative to those specified in this paragraph of this section and, if approved, include those in the

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

a. Installation of the CMS or sorbent trap monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device). See 40 CFR 63.10010(a) for further details. For PM CPMS installations, follow the procedures in 40 CFR 63.10010(h).

b. Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

c. Schedule for conducting initial and periodic performance evaluations.

d. Performance evaluation procedures and acceptance criteria (e.g., calibrations), including the quality control program in accordance with the general requirements of 40 CFR 63.8(d).

e. On-going operation and maintenance procedures, in accordance with the general requirements of 40 CFR 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii).

f. Conditions that define a CMS that is out of control consistent with 40 CFR 63.8(c)(7)(i) and for responding to out of control periods consistent with 40 CFR 63.8(c)(7)(ii) and (c)(8).

g. On-going recordkeeping and reporting procedures, in accordance with the general requirements of 40 CFR 63.10(c), (e)(1), and (e)(2)(i), or as specifically required under 40 CFR Part 63, Subpart UUUUU.

h. Alternatively, the requirements are considered to be met for a particular CMS or sorbent trap monitoring system if:

   i. The CMS or sorbent trap monitoring system is installed, certified, maintained, operated, and quality-assured either according to 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU; and

   ii. The recordkeeping and reporting requirements of 40 CFR Part 75, or Appendix A or B of 40 CFR Part 63, Subpart UUUUU, which pertain to the CMS, are met.

3. If any emission unit(s) cease(s) to operate in a manner that causes the unit(s) to meet the definition of an EGU subject to 40 CFR Part 63, Subpart UUUUU, the permittee must submit the notification in 40 CFR 63.10000(i)(2) no less than 30 days prior to when the EGU will cease complying with 40 CFR Part 63, Subpart UUUUU. **(40 CFR 63.10000(i)(2), 40 CFR 63.10030(f))**

4. The permittee shall comply with all provisions of the National Emission Standards for Hazardous Air Pollutants as specified in 40 CFR Part 63, Subparts A and UUUUU. **(40 CFR Part 63, Subparts A and UUUUU)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGEXISTINGRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

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

Emission Units: EUCATFIREPUMP3, EUHPHSWP15001, EUHPHSWP15002, EUHPHSWP3000.

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMITS

NA

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Each engine in FGEXISTINGRICE shall be installed, maintained, and operated in a satisfactory manner. A list of recommended work practice standards as specified in 40 CFR 63.6602 and Table 2c, Item 1 or the permittee may petition the Administrator pursuant to the requirements of 40 CFR 63.6(g) for alternative work practices. The following are the recommended work practices specified in 40 CFR Part 63, Subpart ZZZZ, Table 2c:

   a. Change oil and filter every 500 hours of operation or annually, whichever comes first, except as allowed in SC III.3.
   b. Inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first; and replace as necessary.
   c. Inspect all hoses and belts every 500 hours of operation or annually, whichever comes first, and replace as necessary.

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

2. The permittee may utilize an oil analysis program in order to extend the specified oil change requirement. The oil analysis must be performed at the same frequency as oil changes are required. The oil analysis must be performed at the same frequency specified for changing the oil in Table 2c of 40 CFR Part 63, Subpart ZZZZ. **(40 CFR 63.6625(i))**

3. The permittee shall maintain and operate each engine in FGEXISTINGRICE per the manufacturer's emission related written instructions or develop a maintenance plan which must provide for the maintenance and operation of the engine in a manner consistent with good air pollution control practices for minimizing emissions. **(40 CFR 63.6625(e), 40 CFR 63.6640(a), 40 CFR Part 63, Subpart ZZZZ, Table 6 Item 9)**

4. The permittee shall minimize the time spent at idle during startup and minimize the startup time of each engine in FGEXISTINGRICE to a period needed for appropriate and safe loading of the engine, not to exceed 30 minutes, after which time the emission standards applicable to all times other than startup apply. **(40 CFR 63.6625(h))**

5. There is no time limit on the use of emergency stationary RICE in emergency situations. **(40 CFR 63.6640(f)(1))**

6. The permittee may not operate each engine in FGEXISTINGRICE for more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The permittee may petition the Administrator for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. **(40 CFR 63.6640(f)(2))**

7. The permittee may operate each engine in FGEXISTINGRICE for up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing as provided in 40 CFR 63.6640 (f)(2). The 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income to supply non-emergency power as part of a financial arrangement with another entity, except as allowed in 40 CFR 63.6640(f)(4)(ii). **(40 CFR 63.6640(f)(4))**

8. If an emergency engine is operating during an emergency and it is not possible to shut down the engine in order to perform the work practice requirements on the schedule required in Table 2c of this subpart, or if performing the work practice on the required schedule would otherwise pose an unacceptable risk under Federal, State, or local law, the work practice can be delayed until the emergency is over or the unacceptable risk under Federal, State, or local law has abated. The work practice should be performed as soon as practicable after the emergency has ended or the unacceptable risk under Federal, State, or local law has abated. Sources must report any failure to perform the work practice on the schedule required and the Federal, State or local law under which the risk was deemed unacceptable. **(40 CFR Part 63, Table 2c, Footnote 1)**

IV. DESIGN/EQUIPMENT PARAMETER(S)

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

V. TESTING/SAMPLING

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

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

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of the occurrence and duration of each malfunction of operation or the air pollution control monitoring equipment. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(2), 40 CFR 63.6660)**

2. For each engine in FGEXISTINGRICE, the permittee shall keep in a satisfactory manner, records of actions taken during periods of malfunction to minimize emissions, including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(a)(5), 40 CFR 63.6660)**

3. For each engine in FGEXISITINGRICE, the permittee shall keep in a satisfactory manner, maintenance records to demonstrate compliance with SC III.1 and the written maintenance plan. The permittee shall keep all records on file and make them available to the department upon request. **(40 CFR 63.6655(d), 40 CFR 63.6655(e), 40 CFR 63.6660)**

4. The permittee shall monitor and record the total hours of operation for each engine in FGEXISTINGRICE per calendar year, recorded through the non-resettable hours meter, in a manner acceptable to the District Supervisor, Air Quality Division. The permittee shall document how many hours are spent for emergency operation; including what classified the operation as emergency and how many hours are spent for non-emergency operation. If the engine is used for the purposes specified in 40 CFR 63.6640(f)(4)(ii), the permittee must keep records of the notification of the emergency situation, and the date, start time, and end time of engine operation. **(40 CFR 63.6655(f))**

5. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 1.0% by weight. **(R 336.1213(3))**

6. The permittee shall conduct and maintain records of a daily (non-certified) visual observation for opacity in order to verify proper firing, whenever an engine is in use for 24 consecutive hours or more. **(R 336.1213(3))**

7. The permittee shall maintain a record of the applicability determination for each engine in FGEXISTINGRICE relative to the requirements of 40 CFR Part 63, Subparts A and ZZZZ. **(40 CFR Part 63, Subpart A, Section 63.10(b)(3))**

See Appendix 3-C

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit to the AQD District Supervisor, a semiannual compliance report, as specified in 40 CFR 63.6650, which contains all deviations during the reporting period from any applicable emission limitation or operating limitation. If there are no deviations from any applicable emission limitations or operating limitations, the report shall contain a statement that there were no deviations during the reporting period. The first report shall cover the period beginning on the applicable compliance date specified in 40 CFR 63.6595 and ending on June 30 (postmarked or delivered by July 31) or December 31 (postmarked or delivered by January 31), whichever date is the first date following the end of the first calendar half after the applicable compliance date. Each subsequent report must cover the semiannual period from January 1 through June 30, or from July 1 through December 31. The subsequent reports must be postmarked or delivered by July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period, except as allowed in 40 CFR 63.6650(b)(5). The compliance report must also contain the following information, as specified in 40 CFR 63.6650(c) and (d):

   a. Company name and address.

   b. Certification of the report by a responsible official.

   c. Date of report and beginning and ending dates of the reporting period.

   d. The number of malfunctions, including a brief description of each event, that occurred during the reporting period and a demonstration that the Malfunction Plan was followed during such events.

   e. The total operating time of the RICE at which the deviation occurred during the reporting period.

   f. The number, duration, and cause of deviations and the corrective action taken.

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

5. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or 71 must report all deviations as defined in 40 CFR Part 63, Subpart ZZZZ in the semiannual monitoring report required by 40 CFR 70.6 (a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a Compliance report pursuant to Table 7 of 40 CFR Part 63, Subpart ZZZZ along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the Compliance report includes all required information concerning deviations from any emission or operating limitation in 40 CFR Part 63, Subpart ZZZZ, submission of the Compliance report shall be deemed to satisfy any obligation to report the same deviations in the semiannual monitoring report. However, submission of a Compliance report shall not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. **(40 CFR 63.6650(f))**

   c. For each engine in FGEXISTINGRICE that is an emergency stationary engine with a site rating of more than 100 brake hp that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii) or that operates for the purpose specified in 40 CFR 63.6640(f)(4)(ii), you must submit an annual report according to the requirements below and as specified in 40 CFR 63.6650(h). **(40 CFR 63.6650(h), 40 CFR 63.6660)**

   a. The report must contain the following information:
      i. Company name and address where the engine is located.
      ii. Date of the report and beginning and ending dates of the reporting period.
      iii. Engine site rating and model year.
      iv. Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.
      v. Hours operated for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).
      vi. Number of hours the engine is contractually obligated to be available for the purposes specified in 40 CFR 63.6640(f)(2)(ii) and (iii).

vii. Hours spent for operation for the purpose specified in 40 CFR 63.6640(f)(4)(ii), including the date, start time, and end time for engine operation for the purposes specified in 40 CFR 63.6640(f)(4)(ii). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.
viii. If there were no deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), a statement that there were no deviations from the fuel requirements during the reporting period.
ix. If there were deviations from the fuel requirements in 40 CFR 63.6604 that apply to the engine (if any), information on the number, duration, and cause of deviations, and the corrective action taken.

b. The permittee shall submit annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in 40 CFR 63.13.
See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

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

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGNEWCIRICE
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

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

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

Emission Units: EUWPDIESEL, EUTRNCNTRDIESEL

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

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

II. MATERIAL LIMIT(S)

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

   See Appendix 3-C

III. PROCESS/OPERATIONAL RESTRICTION(S)

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

of emergency operation, necessary maintenance checks and readiness testing as described in SC III.2.[2] **(R 336.1205(1)(a), R 336.1225, R 336.1702(a))**

2. The permittee may operate not either EUWPDIESEL or EUTRNCNTRDIESEL for no more than 100 hours per calendar year for the purpose of necessary maintenance checks and readiness testing, provided that the tests are recommended by Federal, State, or local government, the manufacturer, the vendor, or the insurance company associated with the engine. The permittee may petition the Department for approval of additional hours to be used for maintenance checks and readiness testing. A petition is not required if the owner or operator maintains records indicating that Federal, State, or local standards require maintenance and testing of emergency internal combustion engines beyond 100 hours per calendar year. EUWPDIESEL may operate up to 50 hours per calendar year in non-emergency situations, but those 50 hours are counted towards the 100 hours per calendar year provided for maintenance and testing.[2] **(40 CFR 60.4211(f))**

3. If EUWPDIESEL and/or EUTRNCNTRDIESEL is a certified engine, the permittee shall meet the following requirements:
   a. Operate and maintain the certified engine and control device according to the manufacturer's emission-related written instructions;
   b. Change only those emission-related settings that are permitted by the manufacturer; and
   c. Meet the requirements as specified in 40 CFR 89, 94, and/or 1068, as they apply to each engine in FGNEWCIRICE.

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

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

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The permittee shall equip and maintain EUWPDIESEL and EUTRNCNTRDIESEL with a non-resettable hours meter to track the operating hours.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4209)**

2. The nameplate capacity of EUWPDIESEL shall not exceed 130 hp, as certified by the equipment manufacturer.[2] **(R 336.1205(1)(a), R 336.1225, 40 CFR 60.4202, 40 CFR 89.112(a))**

3. The nameplate capacity of EUTRNCNTRDIESEL shall not exceed the capacity restrictions (560<kW<=2237) as certified by the equipment manufacturer. **(40 CFR 60.4202)**

V. TESTING/SAMPLING

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

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

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

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

Pollutant	Test Method Reference
PM10/PM2.5	40 CFR Part 51, Appendix M
NOx	40 CFR Part 60, Appendix A
CO	40 CFR Part 60, Appendix A

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

See Appendix 5

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall complete all required calculations in a format acceptable to the AQD District Supervisor by the 30th day of the calendar month, for the previous calendar month, unless otherwise specified in any monitoring/recordkeeping special condition.[2] **(R 336.1205(1)(a))**

2. The permittee shall keep, in a satisfactory manner, records of testing required in SC V.1 or manufacturer certification documentation indicating that EUWPDIESEL and EUTRNCNTRDIESEL meets the applicable requirements contained in the federal Standards of Performance for New Stationary Sources 40 CFR Part 60, Subpart IIII. If EUWPDIESEL or EUTRNCNTRDIESEL becomes uncertified then the permittee must also keep records of a maintenance plan and maintenance activities. The permittee shall keep all records on file and make them available to the Department upon request.[2] **(40 CFR 60.4211(g)(2))**

3. The permittee shall monitor and record the total hours of operation and the hours of operation during non-emergencies for EUWPDIESEL and EUTRNCNTRDIESEL, on a monthly and 12-month rolling time period basis, in a manner acceptable to the AQD District Supervisor. The permittee shall document how many hours are spent for emergency operation of EUWPDIESEL and EUTRNCNTRDIESEL, including what classified the operation as emergency and how many hours are spent maintenance or readiness testing and for non-emergency operation.[2] **(R 336.1205(1)(a), 40 CFR 60.4211, 40 CFR 60.4214(b))**

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

See Appendices 3, 4, and 7

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee shall submit any performance test reports to the AQD Technical Programs Unit and District Office, in a format approved by the AQD. **(R 336.1213(3)(c), R 336.2001(5))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

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

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

IX. OTHER REQUIREMENT(S)

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

2. The permittee shall comply with the provisions of the National Emission Standards for Hazardous Air Pollutants, as specified in 40 CFR Part 63, Subparts A and ZZZZ, as they apply to EUWPDIESEL and EUTRNCNTRDIESEL.[2] **(40 CFR Part 63, Subparts A and ZZZZ, 40 CFR 63.6595)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGAUXBLRS3
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

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

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. The permittee must meet the tune-up and energy assessment work practice standards for each applicable boiler or process heater at the source. **(40 CFR 63.7500(a)(1), 40 CFR Part 63, Subpart DDDDD, Table 3, Nos. 1-4)**

2. The permittee must operate and maintain affected sources in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the AQD that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source. **(40 CFR 63.7500(a)(3))**

3. The permittee may obtain approval from the USEPA Administrator to use an alternative to the tune-up and energy assessment work practice standards. **(40 CFR 63.7500(b))**

4. The permittee must conduct a biennial performance tune-up according to 40 CFR 63.7540(a)(11) as stated in SC III.5, respectively. Each biennial tune-up specified in 40 CFR 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up. **(40 CFR 63.7515(d))**

5. Boilers or process heaters with a heat input capacity of less than 10 million BTU per hour must conduct a biennial tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(11), 40 CFR 63.7500(e))**

6. The permittee shall conduct the tune-up within 30 days of startup, if the unit is not operating on the required date for a tune-up. **(40 CFR 63.7540(a)(12))**

7. The permittee must demonstrate continuous compliance with the tune-up requirement by completing the following: **(40 CFR 63.7540(a)(10))**

a. Inspect the burner, and clean or replace any components of the burner as necessary (the permittee may delay the burner inspection until the next scheduled unit shutdown). At units where entry into a piece of process equipment or into a storage vessel is required to complete the tune-up inspections, inspections are required only during planned entries into the storage vessel or process equipment. **(40 CFR 63.7540(a)(10)(i))**

b. Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available. **(40 CFR 63.7540(a)(10)(ii))**

c. Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly (the permittee may delay the inspection until the next scheduled unit shutdown). Units that produce electricity for sale may delay the inspection until the first outage, not to exceed 36 months from the previous inspection. **(40 CFR 63.7540(a)(10)(iii))**

d. Optimize total emissions of CO. This optimization should be consistent with the manufacturer's specifications, if available, and with any NOx requirement to which the unit is subject. **(40 CFR 63.7540(a)(10)(iv))**

e. Measure the concentrations in the effluent stream of CO in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made). Measurements may be taken using a portable CO analyzer. **(40 CFR 63.7540(a)(10)(v))**

f. Maintain on-site and submit, if requested by the AQD, the most recent periodic report containing the information as listed below. **(40 CFR 63.7540(a)(10)(vi))**

   i. The concentrations of CO in the effluent stream in parts per million by volume, and oxygen in volume percent, measured at high fire or typical operating load, before and after the tune-up of the boiler or process heater. **(40 CFR 63.7540(a)(10)(vi)(A))**

   ii. A description of any corrective actions taken as a part of the tune-up. **(40 CFR 63.7540(a)(10)(vi)(B))**

   iii. The type and amount of fuel used over the 12 months prior to the tune-up, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel used by each unit. **(40 CFR 63.7540(a)(10)(vi)(C))**

8. The permittee must complete the Initial tune ups on all affected units except as provided in 40 CFR 63.7510(j) and 40 CFR 63.7540(a)(13). **(40 CFR 63.7510(e))**

9. For affected sources (as defined in 40 CFR 63.7490) that have not operated since the previous compliance demonstration and more than one year has passed since the previous compliance demonstration, the permittee must complete a subsequent tune-up within 30 days of startup by following the procedures described in SC III.7.a through SC III.7.f. **(40 CFR 63.7515(9))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

NA

V. TESTING/SAMPLING

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

NA

VI. MONITORING/RECORDKEEPING

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

1. The permittee shall maintain sufficient records to demonstrate that the sulfur content for each shipment of fuel oil received is less than 0.4% by weight. **(R 336.1213(3))**

2. The permittee must keep a copy of each notification and report submitted to comply with 40 CFR Part 63, Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that the permittee submitted, according to the requirements in 40 CFR 63.10(b)(2)(xiv). **(40 CFR 63.7555(a)(1))**

3. The permittee must keep each record on site, or they must be accessible from on-site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. The permittee can keep the records off site for the remaining 3 years. **(40 CFR 63.7560(a), (b), and (c))**

See Appendix 3-C (Fuel Oil Sulfur Monitoring)

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

4. The permittee must submit boiler tune-up compliance reports. Compliance reports must be postmarked or submitted by March 15 of the year following the tune-up and must cover the applicable 1, 2, or 5-year period starting from January 1 of the year following the previous tune-up to December 31 (of the latest tune-up year). Compliance reports must be submitted using the Compliance and Emissions Data Reporting Interface (CEDRI) which is accessed through the USEPA's Central Data Exchange (CDX) (www.epa.gov/cdx). If the reporting form is not available in CEDRI at the time the compliance report is due, a hardcopy of the compliance report shall be submitted to the state and USEPA Region 5. At the discretion of the Administrator, the permittee must submit these reports in the format specified by the Administrator. **(40 CFR 63.7550(b), 40 CFR 63.10(a)(5), 40 CFR 63.7550(h)(3))**

5. Unless the USEPA Administrator has approved a different schedule for submission of reports under 40 CFR 63.10(a), the permittee must submit each report, according to paragraph (h) of 40 CFR 63.7550, stated in SC VII.5, by the date in Table 9 of 40 CFR Part 63, Subpart DDDDD and according to the requirements in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below. For units that are subject only to a requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b, and not subject to emission limits or operating limits, the permittee may submit only a 5-year compliance report, as specified in paragraphs (b)(1) through (4) of 40 CFR 63.7550, as listed below, instead of a semi-annual compliance report. **(40 CFR 63.7550(a) & (b))**
   a. Each semi-annual compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. 5-year compliance reports must cover the 5-year period from January 1 to December 31. **(40 CFR 63.7550(b)(3))**
   b. Each semi-annual compliance report must be postmarked or submitted no later than September 15 or March 15, whichever date is the first date following the end of the semiannual reporting period. 5-year compliance reports must be postmarked or submitted no later than March 15. **(40 CFR 63.10(a)(5), 40 CFR 63.7550(b)(4), 40 CFR 63.7550(b)(5))**

6. The permittee must include the following information in the compliance report. **(40 CFR 63.7550(a) & (c))**
   a. If the facility is subject to the requirements of a tune up the permittee must submit a compliance report with the information in paragraphs (c)(5)(i) through (iii), (xiv), and (xvii) of 40 CFR 63.7550. **(40 CFR 63.7550(c)(1))**
   b. 40 CFR 63.7550(c)(5) is as follows:
      i. Company and Facility name and address. **(40 CFR 63.7550(c)(5)(i))**
      ii. Process unit information, emissions limitations, and operating parameter limitations. **(40 CFR 63.7550(c)(5)(ii))**
      iii. Date of report and beginning and ending dates of the reporting period. **(40 CFR 63.7550(c)(5)(iii))**
      iv. Include the date of the most recent tune-up for each unit subject to only the requirement to conduct a 5-year tune-up according to 40 CFR 63.7540(a)(12), stated in SC IX.5.b. Include the date of the most recent burner inspection if it was not done on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. **(40 CFR 63.7550(c)(5)(xiv))**
      v. Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report. **(40 CFR 63.7550(c)(5)(xvii))**

7. The permittee must submit the reports according to the procedures specified in paragraph (h)(3) of 40 CFR 63.7550, as listed below. **(40 CFR 63.7550(h))**
   a. The permittee must submit all reports required by Table 9 of 40 CFR Part 63, Subpart DDDDD electronically to the USEPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the USEPA's CDX.) The permittee must use the appropriate electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD. Instead of using the electronic report in CEDRI for 40 CFR Part 63, Subpart DDDDD, the permittee may submit an alternate electronic file consistent with the XML schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*), once the XML schema is available. If the reporting form specific to 40 CFR Part 63, Subpart DDDDD is not available in CEDRI at the time that the report is due, the permittee must submit the report to the Administrator at the appropriate address listed in 40 CFR 63.13. The permittee must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. **(40 CFR 63.7550(h)(3))**

8. The permittee must report each instance in which the permittee did not meet each applicable operating limit in Tables 3 and 4 to 40 CFR Part 63, Subpart DDDDD. These instances are deviations from the operating limits, respectively, in 40 CFR Part 63, Subpart DDDDD. These deviations must be reported according to the requirements in Section 63.7550. **(40 CFR 63.7540(b))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

1. The permittee shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. **(40 CFR Part 63, Subparts A and DDDDD)**

2. The permittee must be in compliance with the work practice standards (tune ups, energy assessment) in 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7505(a))**

3. The permittee shall comply with the General Provisions in 40 CFR 63.1 through 40 CFR 63.15 apply to this source as indicated in Table 10 of 40 CFR Part 63, Subpart DDDDD. **(40 CFR 63.7565, Table 10)**

Footnotes:
[1] This condition is state only enforceable and was established pursuant to Rule 201(1)(b).
[2] This condition is federally enforceable and was established pursuant to Rule 201(1)(a).

FGPARTSCLEANERS
FLEXIBLE GROUP CONDITIONS

DESCRIPTION

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

Emission Unit: EUPARTSCLEANERS

POLLUTION CONTROL EQUIPMENT

NA

I. EMISSION LIMIT(S)

NA

II. MATERIAL LIMIT(S)

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

III. PROCESS/OPERATIONAL RESTRICTION(S)

1. Cleaned parts shall be drained for no less than 15 seconds or until dripping ceases. **(R 336.1611(2)(b), R 336.1707(3)(b))**

2. The permittee shall perform routine maintenance on each cold cleaner as recommended by the manufacturer. **(R 336.1213(3))**

IV. DESIGN/EQUIPMENT PARAMETER(S)

1. The cold cleaner must meet one of the following design requirements:

   a. The air/vapor interface of the cold cleaner is no more than ten square feet. **(R 336.1281(2)(h))**

   b. The cold cleaner is used for cleaning metal parts and the emissions are released to the general in-plant environment. **(R 336.1285((2)(r)(iv))**

2. The cold cleaner shall be equipped with a device for draining cleaned parts. **(R 336.1611(2)(b), R 336.1707(3)(b))**

3. All new and existing cold cleaners shall be equipped with a cover and the cover shall be closed whenever parts are not being handled in the cold cleaner. **(R 336.1611(2)(a), R 336.1707(3)(a))**

4. The cover of a new cold cleaner shall be mechanically assisted if the Reid vapor pressure of the solvent is more than 0.3 psia or if the solvent is agitated or heated. **(R 336.1707(3)(a))**

5. If the Reid vapor pressure of any solvent used in a new cold cleaner is greater than 0.6 psia; or, if any solvent used in a new cold cleaner is heated above 120 degrees Fahrenheit, then the cold cleaner must comply with at least one of the following provisions:

a. The cold cleaner must be designed such that the ratio of the freeboard height to the width of the cleaner is equal to or greater than 0.7. **(R 336.1707(2)(a))**

b. The solvent bath must be covered with water if the solvent is insoluble and has a specific gravity of more than 1.0. **(R 336.1707(2)(b))**

c. The cold cleaner must be controlled by a carbon adsorption system, condensation system, or other method of equivalent control approved by the AQD. **(R 336.1707(2)(c))**

V. TESTING/SAMPLING

NA

VI. MONITORING/RECORDKEEPING

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

1. For each new cold cleaner in which the solvent is heated, the solvent temperature shall be monitored and recorded at least once each calendar week during routine operating conditions. **(R 336.1213(3))**

2. The permittee shall maintain the following information on file for each cold cleaner: **(R 336.1213(3))**

   a. A serial number, model number, or other unique identifier for each cold cleaner.

   b. The date the unit was installed, manufactured or that it commenced operation.

   c. The air/vapor interface area for any unit claimed to be exempt under Rule 281(2)(h).

   d. The applicable Rule 201 exemption.

   e. The Reid vapor pressure of each solvent used.

   f. If applicable, the option chosen to comply with Rule 707(2).

3. The permittee shall maintain written operating procedures for each cold cleaner. These written procedures shall be posted in an accessible, conspicuous location near each cold cleaner. **(R 336.1611(3), R 336.1707(4))**

4. As noted in Rule 611(2)(c) and Rule 707(3)(c), if applicable, an initial demonstration that the waste solvent is a safety hazard shall be made prior to storage in non-closed containers. If the waste solvent is a safety hazard and is stored in non-closed containers, verification that the waste solvent is disposed of so that not more than 20%, by weight, is allowed to evaporate into the atmosphere shall be made on a monthly basis. **(R 336.1213(3), R 336.1611(2)(c), R 336.1707(3)(c))**

VII. REPORTING

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

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

3. Annual certification of compliance pursuant to General Conditions 19 and 20 of Part A. The report shall be postmarked or received by the appropriate AQD District Office by March 15 for the previous calendar year. **(R 336.1213(4)(c))**

See Appendix 8

VIII. STACK/VENT RESTRICTION(S)

NA

IX. OTHER REQUIREMENT(S)

NA

E. NON-APPLICABLE REQUIREMENTS

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

APPENDICES

Appendix 1-A. Acronyms and Abbreviations

Common Acronyms		Pollutant / Measurement Abbreviations	
AQD	Air Quality Division	acfm	Actual cubic feet per minute
BACT	Best Available Control Technology	BTU	British Thermal Unit
CAA	Clean Air Act	°C	Degrees Celsius
CAM	Compliance Assurance Monitoring	CO	Carbon Monoxide
CEM	Continuous Emission Monitoring	CO_2e	Carbon Dioxide Equivalent
CEMS	Continuous Emission Monitoring System	dscf	Dry standard cubic foot
CFR	Code of Federal Regulations	dscm	Dry standard cubic meter
COM	Continuous Opacity Monitoring	°F	Degrees Fahrenheit
Department/ department	Michigan Department of Environment, Great Lakes, and Energy	gr	Grains
		HAP	Hazardous Air Pollutant
EGLE	Michigan Department of Environment, Great Lakes, and Energy	Hg	Mercury
		hr	Hour
EU	Emission Unit	HP	Horsepower
FG	Flexible Group	H_2S	Hydrogen Sulfide
GACS	Gallons of Applied Coating Solids	kW	Kilowatt
GC	General Condition	lb	Pound
GHGs	Greenhouse Gases	m	Meter
HVLP	High Volume Low Pressure*	mg	Milligram
ID	Identification	mm	Millimeter
IRSL	Initial Risk Screening Level	MM	Million
ITSL	Initial Threshold Screening Level	MW	Megawatts
LAER	Lowest Achievable Emission Rate	NMOC	Non-methane Organic Compounds
MACT	Maximum Achievable Control Technology	NO_x	Oxides of Nitrogen
MAERS	Michigan Air Emissions Reporting System	ng	Nanogram
MAP	Malfunction Abatement Plan	PM	Particulate Matter
MSDS	Material Safety Data Sheet	PM10	Particulate Matter equal to or less than 10 microns in diameter
NA	Not Applicable		
NAAQS	National Ambient Air Quality Standards	PM2.5	Particulate Matter equal to or less than 2.5 microns in diameter
NESHAP	National Emission Standard for Hazardous Air Pollutants	pph	Pounds per hour
		ppm	Parts per million
NSPS	New Source Performance Standards	ppmv	Parts per million by volume
NSR	New Source Review	ppmw	Parts per million by weight
PS	Performance Specification	%	Percent
PSD	Prevention of Significant Deterioration	psia	Pounds per square inch absolute
PTE	Permanent Total Enclosure	psig	Pounds per square inch gauge
PTI	Permit to Install	scf	Standard cubic feet
RACT	Reasonable Available Control Technology	sec	Seconds
ROP	Renewable Operating Permit	SO_2	Sulfur Dioxide
SC	Special Condition	TAC	Toxic Air Contaminant
SCR	Selective Catalytic Reduction	Temp	Temperature
SNCR	Selective Non-Catalytic Reduction	THC	Total Hydrocarbons
SRN	State Registration Number	tpy	Tons per year
TEQ	Toxicity Equivalence Quotient	µg	Microgram
USEPA/EPA	United States Environmental Protection Agency	µm	Micrometer or Micron
		VOC	Volatile Organic Compounds
VE	Visible Emissions	yr	Year

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

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

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

- For the purposes of the Consent Decree, every term expressly defined by this Appendix shall have the meaning given that term herein. Every other term used in the Consent Decree that is also a term used under the Act or in a federal regulation implementing the Act shall mean in the Consent Decree what such term means under the Act or those regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 4)**
- A "30-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 29 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 29 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 30 Unit Operating Days by the total heat input during the 30 Unit Operating Days. A new 30-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 30-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 5)**
- A "90-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the total pounds of NO_x or SO_2 emitted from the Unit during the current Unit Operating Day and the previous 89 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the current Unit Operating Day and the previous 89 Unit Operating Days; and third, divide the total number of pounds of NO_x or SO_2 emitted during the 90 Unit Operating Days by the total heat input during the 90 Unit Operating Days. A new 90-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 90-Day Rolling Average Emission Rate shall include all emissions that occur during all periods within any Unit Operating Day, including emissions from startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 6)**
- A "365-Day Rolling Average Emission Rate" for a Unit shall be expressed in lb/MMBTU and calculated in accordance with the following procedure: first, sum the pounds of the pollutant in question emitted from the Unit during the most recent Unit Operating Day and the previous 364 Unit Operating Days; second, sum the total heat input to the Unit in MMBTU during the most recent Unit Operating Day and the previous 364 Unit Operating Days; and third, divide the total number of pounds of the pollutant emitted during the 365 Unit Operating Days by the total heat input during the 365 Unit Operating Days. A new 365-Day Rolling Average Emission Rate shall be calculated for each new Unit Operating Day. Each 365-Day Rolling Average Emission Rate shall include all emissions that occur during all periods of operation, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 7)**
- "Baghouse" means a full stream (fabric filter or membrane) particulate emissions control device. Full stream is defined as capturing the entire stream of exhaust gas with no concurrent by-pass. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 8)**
- "Campbell" means Consumers' J.H. Campbell Generating Plant consisting of three electric utility steam-generating units designated as Unit l (260 MW), Unit 2 (360 MW), and Unit 3 (835 MW) and related equipment, located in West Olive, Ottawa County, Michigan. Campbell Unit 3 is co-owned by Consumers (approximately 93%) along with Wolverine Power Supply Cooperative and the Michigan Public Power Association. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 10)**
- "CEMS" or "Continuous Emission Monitoring System," means, for obligations involving the monitoring of NO_x and SO_2 emissions under the Consent Decree, the devices defined in 40 CFR 72.2 and installed and

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

- "Clean Air Act" or "CAA" or "Act" means the federal Clean Air Act, 42 U.S.C. §§ 7401-7671q, and it's implementing regulations. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 13)**
- "Cobb" means, for purposes of the Consent Decree, Consumers' B.C. Cobb Generating Plant consisting of two electric utility steam-generating units designated as Unit 4 (160 MW) and Unit 5 (160 MW) and related equipment, located in Muskegon, Muskegon County, Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 14)**
- "Consent Decree" means Consent Decree ("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014") and its Appendices. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 15)**
- "Consumers" means Consumers Energy Company. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 16)**
- "Consumers System" means the Campbell, Cobb, Karn, Weadock, and Whiting facilities as defined herein. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 17)**
- "Continuously Operate" or "Continuous Operation" means that when a pollution control technology or combustion control is required to be used at a Unit pursuant to the Consent Decree (including, but not limited to, SCR, FGD, DSI, ESP, Baghouse, or Low NOx Combustion System), it shall be operated at all times that the Unit it serves is in operation, except the SCRs on Campbell Units 2 and 3 need not be operated during scheduled maintenance on the applicable Unit's Urea Based Ammonia System and consistent with the technological limitations, manufacturers' specifications, good engineering and maintenance practices (including Campbell Unit 2 and Unit 3 scheduled Urea Based Ammonia System outages), and good air pollution control practices for minimizing emissions (as defined in 40 CFR 60.11(d)), as applicable, for such equipment and the Unit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 18)**
- "Date of Entry" means the date the Consent Decree was signed by the United States District Court Judge (i.e. November 4, 2014). **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 19)**
- "Day" means calendar day unless otherwise specified in the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 21)**
- "Dry Sorbent Injection" or "DSI" means a process in which a sorbent is pneumatically injected into the ducting downstream of where the coal is combusted and flue gas is produced, and upstream of the PM Control Device. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 22)**
- "Electrostatic Precipitator" or "ESP" means a device for removing particulate matter from combustion gases by imparting an electric charge to the particles and then attracting them to a metal plate or screen of opposite charge before the combustion gases are exhausted to the atmosphere. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 23)**
- "Emission Rate" for a given pollutant means the number of pounds of that pollutant emitted per million British Thermal Units of heat input (lb/MMBTU), calculated in accordance with each applicable 30, 90 or 365-Day Rolling Average Emission Rate definition. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 24)**
- "Flue Gas Desulfurization System" or "FGD" means a pollution control device that employs flue gas desulfurization technology, including an absorber or absorbers utilizing lime or limestone, or a sodium based material, for the reduction of SO_2 emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 27)**
- "Fossil Fuel" means any hydrocarbon fuel, including coal, petroleum coke, petroleum oil, or natural gas. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 29)**
- "Full Stream Operation" is defined as the design configuration of a control device such that it captures the

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

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

- "Selective Catalytic Reduction" or "SCR" means an air pollution control device for reducing NO_x emissions in which ammonia ("NH_3") is added to the flue gas and then passed through layers of a catalyst material. The ammonia and NO_x in the flue gas stream react on the surface of the catalyst, forming nitrogen ("N_2") and water vapor. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 61)**
- "SO_2" means sulfur dioxide, measured in accordance with the provisions of the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 62)**
- "SO_2 Allowance" means an authorization to emit a specified amount of SO_2 that is allocated or issued under an emissions trading or marketable permit program of any kind established under the Clean Air Act or the Michigan SIP; provided, however, that with respect to any such program that first applies to emissions occurring after December 31, 2011, an "SO_2 Allowance" shall include an allowance created and allocated to a Consumers System Unit under such program only for control periods starting on or after November 4, 2018. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 63)**
- "State" means the State of Michigan. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 64)**
- "State Implementation Plan" or "SIP" means regulations and other materials promulgated by a state for purposes of meeting the requirements of the Act that have been approved by USEPA pursuant to Section IIO of the Act, 42 U.S.C. § 74IO. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 65)**
- "Surrender" or "Surrender of Allowances" means, for purposes of SO_2 or NO_x allowances, permanently surrendering allowances from the accounts administered by USEPA and Michigan for all Units in the Consumers System, so that such allowances can never be used thereafter to meet any compliance requirements under the Act, a SIP, or the Consent Decree. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 66)**
- "System-Wide Annual NO_x Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of NO_x that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of NO_x during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 67)**
- "System-Wide Annual SO_2 Tonnage Limitation" means the limitations, as specified in the Consent Decree, on the number of tons of SO_2 that may be emitted from Campbell, Cobb, Kam, Weadock, and Whiting, collectively, during the relevant calendar year (i.e., January 1 through December 31), and shall include all emissions of SO_2 during all periods of operations, including startup, shutdown, and malfunction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 68)**
- "Title V Permit" means the permit required of Consumers' major sources pursuant to Subchapter V of the Act, 42 U.S.C. §§ 7661-7661e. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 69)**
- "Unit" means collectively, the coal pulverizer, stationary equipment that feeds coal to the boiler, the boiler that produces steam for the steam turbine, the steam turbine, the generator, the equipment necessary to operate the generator, steam turbine, and boiler, and all ancillary equipment, including pollution control equipment and systems necessary for production of electricity. An electric steam generating station may comprise one or more Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 70)**
- "Urea Based Ammonia System" or "UBAS" means a type of ammonia feed system for SCRs where solid urea pellets are stored in a silo. Upon use,the solid urea is heated to liquid, thermally decomposed to ammonia, and injected into the SCR as the reagent for the NO_x reduction reaction. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 71)**
- "Weadock" means, for purposes of the Consent Decree, Consumers' J.C. Weadock Generating Plant consisting of two electric utility steam-generating Units designated as Unit 7 (155 MW) and Unit 8 (155 MW) and related equipment, located in Essexville, Bay County, Michigan. **("U.S. v Consumers Energy**

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

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

Appendix 2. Schedule of Compliance

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

Appendix 3. Monitoring Requirements

Appendix 3-A. Continuous Opacity Monitoring Systems

(This section applies to each boiler.)

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

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

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

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

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

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

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

(This section applies to each boiler.)

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

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

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

Appendix 3-C. Fuel Oil Sulfur Monitoring

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

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

(This section applies to Units 1 and 2.)

The Continuous Emissions Monitoring Systems (CEMS) performance specifications defined in 40 CFR Part 75, Appendix B, are adopted. The Certified SO_2 and CO_2 monitors will be used to determine sulfur dioxide emissions. The data reduction procedures defined in R 336.2175 will be used to determine SO_2 lbs/MMBTU. On the last day of each calendar month, the CEMS data recording system will generate and record an "operating monthly average" as the average of the previous 31 operating days.

Appendix 3-E. PM CEMS

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

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

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

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

Appendix 3-F. Optimization of Baghouses

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

Consumers shall:

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

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

Appendix 4. Recordkeeping

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

Appendix 5. Testing Procedures

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

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

Test Methods and Procedures for Boiler #3

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

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

2. Opacity: Method 9.

3. SO_2: Method 6C shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the SO_2 sample.

2. NO_x: Method 7E shall be in the same sample site selected for particulate sample. The emission rate correction factor, integrated sampling and analysis procedure of Method 3A shall be used to determine the O_2 or CO_2 concentration, and shall be taken simultaneously and in the same point as the NO_x sample.

PM Emissions Testing and Monitoring Requirements

- Annually unless a Unit is Retired or Refueled to Natural Gas, Consumers shall conduct a stack test for PM pursuant to Paragraph 154 of the Consent Decree. The annual performance test requirement imposed on Consumers by this paragraph may be satisfied by stack tests conducted by Consumers as may be required by other conditions in its ROP for any year that such stack tests are required. Consumers may perform testing every other year, rather than every year, provided that two of the most recently completed test results from tests conducted in accordance with the methods and procedures specified above demonstrate that the PM emissions are equal to or less than 0.010 lb/MMBTU. Consumers shall perform testing every year, rather than every other year, beginning in the year immediately following any test result demonstrating that the PM emissions are greater than 0.010 lb/MMBTU.. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 153)**

- To determine compliance with the PM Emission Rate established in Subsections VI.B (Unit-Specific PM Requirements at Campbell Units 1 and 2), Consumers shall use the applicable reference methods and procedures (filterable portion only) specified in its ROP and the Michigan SIP for Campbell Units 1 and 2. Each test shall consist of three separate runs performed under representative operating conditions not including periods of startup, shutdown, or malfunction. The sampling time for each run associated with a Unit controlled by a Baghouse shall be at least 120 minutes and the volume of each run shall be at least 1.70 dry standard cubic meters (60 dry standard cubic feet). Consumers shall calculate the PM Emission Rate from the stack test results in accordance with 40 CFR 60.8(f). The results of each PM stack test shall be submitted to EGLE within 60 Days of completion of each test. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 154)**

- As an alternative to the PM testing required in this Appendix (PM Emissions Testing and Monitoring Requirements; beginning at paragraph 153) of the Consent Decree, following the installation and operation of PM CEMS as required by Appendix 3-E (PM CEMS), Consumers, at its sole discretion, may seek USEPA approval pursuant to Section XIII (Review and Approval of Submittals; beginning at paragraph 193) of the Consent Decree to forego stack testing and instead demonstrate continuous compliance with an applicable filterable PM Emission Rate by using the PM CEMS data on a 3-hour rolling average basis. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 157)**

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

Appendix 6. Permits to Install

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

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

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

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

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

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

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

Appendix 7. Emission Calculations

Determination of Unit Specific NOx or SO_2 Mass Emissions for Those Units Where 40 CFR Part 75 NOx or SO_2 Mass Emissions Are Measured at a Common Stack

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

For J.H. Campbell Units 1 and 2, NO_x mass emission rates are monitored at the associated common stacks via the use of NO_x concentration and flow CEMS. In addition, each of the preceding individual units are equipped with duct-level NO_x and diluent (i.e., CO_2) concentration CEMS to permit the determination of unit specific NO_x lb/MMBTU emission rates. The following procedures shall be used to calculate unit level NO_x mass emission rates for purposes of conducting rolling average NO_x lb/MMBTU calculations. If Campbell Units EUBOILER1 and EUBOILER2 elect to install unit level SO_2 CEMS only in lieu of installing both unit level SO_2 CEMS and Flow CEMS, the same procedure shall be followed for calculating unit level SO_2 mass emissions except that the value of K in Paragraph c. shall equal 1.660 x 10-7 (lb/scf)/ppm.

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

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

Where,

HI = *Common stack hourly heat input rate during unit operation, MMBTU/hr*
Q_w = *Hourly average volumetric flow rate during unit operation, wet basis, scfh*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%\ CO_{2w}$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

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

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

Where,

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

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

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

Where,

E = *Pollutant emission rate during unit operation, lb/MMBTU*
K = *$1.194x10^{-7}$for NO_X (lb/scj)/ppm*
C_h = *Hourly average NO_x concentration during unit operation, ppm*
F_c = *Carbon-based F-factor, listed in 40 CFR 75, Appendix A, Section 3.3.5 for each fuel, scf/MMBTU*
$\%CO_2$ = *Hourly concentration of CO_2 during unit operation, percent CO_2*

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

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

Where,

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

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

Where,

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

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

Appendix 8. Reporting

A. Annual, Semiannual, and Deviation Certification Reporting

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

B. Other Reporting

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

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

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

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

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

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

Reporting requirements per 40 CFR Part 60, Subpart D.

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

1. Opacity: EE are defined as any 6-minute period during which the average opacity of emissions exceeds 20% opacity, except that one 6-minute average per hour of up to 27% need not be reported.

2. SO_2: EE are defined as any 3-hour period during which the average emissions (arithmetic average of 3 contiguous one-hour periods) of SO_2 as measured by a CEMS exceeded the applicable standard under Section 60.43, per Section 60.45(g)(2).

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

Appendix 9. Acid Rain Permit

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

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

The Acid Rain Permit Contents

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

   References to statutory and regulatory authorities, and with comments, notes, and justification that apply to the source in general;

2. Terms and conditions including:

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

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

   Any applicable nitrogen oxides compliance plan. Unless they are coal fired utility units regulated pursuant to Sections 404, 405, or 409 of the federal Clean Air Act, new units are not subject to the acid rain nitrogen oxides requirements (40 CFR 76.1(a)).

3. The permit application that this source submitted, as corrected by the AQD. The owners and operators of the source must comply with the standard requirements and special provisions set forth in the application.

Statement of Basis

Statutory and Regulatory Authorities.

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

For further information contact:

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

Telephone: 517-416-4631
Facsimile: 517-780-7855

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

Terms and Conditions:

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

		2020	2021	2022	2023	2024
Unit 1	SO_2 allowances	8113	8113	8113	8113	8113
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 1. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.45 lb/MMBTU** for Phase I tangentially fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

		2020	2021	2022	2023	2024
Unit 2	SO_2 allowances	9702	9702	9702	9702	9702
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 2. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.68 lb/MMBTU** for cell burner boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

Terms and Conditions (cont.):

		2020	2021	2022	2023	2024
Unit 3	SO_2 allowances	27529	27529	27529	27529	27529
	NOx Emission Limits	Pursuant to 40 CFR part 76, the State of Michigan Department of Environment, Great Lakes, and Energy, Air Quality Division approves a NOx standard emissions limitation compliance plan for unit 3. The NOx compliance plan is effective beginning 2017. Under the NOx compliance plan, this unit's annual average NOx emissions rate for each year, determined in accordance with 40 CFR part 75, shall not exceed the applicable emission limitation, under 40 CFR 76.7(a)(2), of **0.46 lb/MMBTU** for Phase II dry bottom wall-fired boilers. In addition to the described NOx compliance plan, this unit shall comply with all other applicable requirements of 40 CFR part 76, including the duty to reapply for a NOx compliance plan and requirements covering excess emissions.				

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

Permit Application: (attached)

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

United States
Environmental Protection Agency
Acid Rain Program

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

Acid Rain Permit Application

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

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

STEP 1

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

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

STEP 2

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

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

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

STEP 3

Read the standard requirements.

Permit Requirements

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

Monitoring Requirements

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

Sulfur Dioxide Requirements

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

Nitrogen Oxides Requirements

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

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

STEP 3, Cont'd.

Excess Emissions Requirements

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

Recordkeeping and Reporting Requirements

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

Liability

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

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

STEP 3, Cont'd.

Effect on Other Authorities

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

(1) Except as expressly provided in title IV of the Act, exempting or excluding the owners and operators and, to the extent applicable, the designated representative of an affected source or affected unit from compliance with any other provision of the Act, including the provisions of title I of the Act relating to applicable National Ambient Air Quality Standards or State Implementation Plans;

(2) Limiting the number of allowances a source can hold; *provided,* that the number of allowances held by the source shall not affect the source's obligation to comply with any other provisions of the Act;

(3) Requiring a change of any kind in any State law regulating electric utility rates and charges, affecting any State law regarding such State regulation, or limiting such State regulation, including any prudence review requirements under such State law;

(4) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(5) Interfering with or impairing any program for competitive bidding for power supply in a State in which such program is established.

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

Certification

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

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

EPA Form 7610-16 (Revised 12-2016)

United States
Environmental Protection Agency
Acid Rain Program

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

Acid Rain NO_X Compliance Plan

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

Page 1

This submission is: ☐ New ☒ Revised

Page 1 of 1

STEP 1
Indicate plant name, State, and Plant code from the current Certificate of Representation covering the facility.

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

STEP 2

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

	ID# **1** Type **T**	ID# **2** Type **CB**	ID# **3** Type **DBW**	ID# Type	ID# Type	ID# Type
(a) Standard annual average emission limitation of 0.50 lb/mmBtu (for Phase I dry bottom wall-fired boilers)						
(b) Standard annual average emission limitation of 0.45 lb/mmBtu (for Phase I tangentially fired boilers)	X					
(c) Standard annual average emission limitation of 0.46 lb/mmBtu (for Phase II dry bottom wall-fired boilers)			X			
(d) Standard annual average emission limitation of 0.40 lb/mmBtu (for Phase II tangentially fired boilers)						
(e) Standard annual average emission limitation of 0.68 lb/mmBtu (for cell burner boilers)		X				
(f) Standard annual average emission limitation of 0.86 lb/mmBtu (for cyclone boilers)						
(g) Standard annual average emission limitation of 0.80 lb/mmBtu (for vertically fired boilers)						
(h) Standard annual average emission limitation of 0.84 lb/mmBtu (for wet bottom boilers)						
(i) NO_X Averaging Plan (include NO_X Averaging form)						
(j) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(A) (check the standard emission limitation box above for most stringent limitation applicable to any unit utilizing stack)						
(k) Common stack pursuant to 40 CFR 75.17(a)(2)(i)(B) with NO_X Averaging (check the NO_X Averaging Plan box and include NO_X Averaging Form))						
(l) EPA-approved common stack apportionment method pursuant to 40 CFR 75.17(a)(2)(i)(C), (a)(2)(iii)(B), or (b)(2)						

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J.H. Campbell Plant Name (from Step 1)	NO_x Compliance - Page 2 Page 1 of 1

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

January 1, 2017

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

Special Provisions

General.

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

Certification

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

Name **John P. Broschak**	
Signature John P. Broschak	Date 6/29/17

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

Description of CSAPR Monitoring Provisions

The CSAPR subject units, and the unit-specific monitoring provisions, at this source are identified in the following tables. These units are subject to the requirements for the CSAPR NO_X Annual Trading Program, CSAPR NO_X Ozone Season Group 2 Trading Program, and CSAPR SO_2 Group 1 Trading Program, which are included below as Sections I, II, and III, respectively.

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

- Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO_2 monitoring) or 40 CFR Part 75, Subpart H (for NO_X monitoring)
- Excepted monitoring system requirements for gas- and oil-fired units pursuant to 40 CFR Part 75, Appendix D
- Excepted monitoring system requirements for gas- and oil-fired peaking units pursuant to 40 CFR Part 75, Appendix E
- Low Mass Emissions excepted monitoring (LME) requirements for gas- and oil-fired units pursuant to 40 CFR 75.19
- USEPA-approved alternative monitoring system requirements pursuant to 40 CFR Part 75, Subpart E

Unit ID: 1	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 2	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

Unit ID: 3	
Parameter	Monitoring Methodology
SO_2	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B
NO_X	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart H
Heat Input	Continuous emission monitoring system or systems (CEMS) requirements pursuant to 40 CFR Part 75, Subpart B (for SO2 monitoring) or 40 CFR Part 75, Subpart H (for NOX monitoring)

1. The above description of the monitoring used by a unit does not change, create an exemption from, or otherwise affect the monitoring, recordkeeping, and reporting requirements applicable to the unit under 40 CFR 97.430 through 97.435 (CSAPR NO_X Annual Trading Program), 97.830 through 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.635 (CSAPR SO_2 Group 1 Trading Program). The monitoring, recordkeeping and reporting requirements applicable to each unit are included below in the standard conditions for the applicable CSAPR trading programs.

2. Owners and operators must submit to the Administrator a monitoring plan for each unit in accordance with 40 CFR 75.53, 75.62 and 75.73, as applicable. The monitoring plan for each unit is available at the USEPA's website at https://www.epa.gov/airmarkets/clean-air-markets-monitoring-plans-part-75-sources.

3. Owners and operators that want to use an alternative monitoring system must submit to the Administrator a petition requesting approval of the alternative monitoring system in accordance with 40 CFR Part 75, Subpart E and 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative monitoring system is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

4. Owners and operators that want to use an alternative to any monitoring, recordkeeping, or reporting requirement under 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program) must submit to the Administrator a petition requesting approval of the alternative in accordance with 40 CFR 75.66 and 97.435 (CSAPR NO_X Annual Trading Program), 97.835 (CSAPR NO_X Ozone Season Group 2 Trading Program), and/or 97.635 (CSAPR SO_2 Group 1 Trading Program). The Administrator's response approving or disapproving any petition for an alternative to a monitoring, recordkeeping, or reporting requirement is available on the USEPA's website at https://www.epa.gov/airmarkets/part-75-petition-responses.

5. The descriptions of monitoring applicable to the unit included above meet the requirement of 40 CFR 97.430 through 97.434 (CSAPR NO_X Annual Trading Program), 97.830 through 97.834 (CSAPR NO_X Ozone Season Group 2 Trading Program), and 97.630 through 97.634 (CSAPR SO_2 Group 1 Trading Program), and therefore minor permit modification procedures, in accordance with 40 CFR 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B), may be used to add or change this unit's monitoring system description.

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

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

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

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

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Annual units at a CSAPR NO_X Annual source are in excess of the CSAPR NO_X Annual emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall hold the CSAPR NO_X Annual allowances required for deduction under 40 CFR 97.424(d); and

(B). The owners and operators of the source and each CSAPR NO_X Annual unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(2) CSAPR NO_X Annual assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such State exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Annual allowances available for deduction for such control period under 40 CFR 97.425(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.425(b), of multiplying— (A) The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and (B) The amount by which total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Annual allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the state NO_X Annual trading budget under 40 CFR 97.410(a) and the state's variability limit under 40 CFR 97.410(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart AAAAA or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the State and Indian country within the borders of such State during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Annual units at CSAPR NO_X Annual sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Annual allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Annual allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart AAAAA and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015, or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(ii). A CSAPR NO_X Annual unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.430(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Annual allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Annual allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Annual allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart AAAAA.

(6) Limited authorization. A CSAPR NO_X Annual allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Annual Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Annual allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Annual allowances in accordance with 40 CFR Part 97, Subpart AAAAA.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.430 through 97.435, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.406(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.416 for the designated representative for the source and each CSAPR NO_X Annual unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.416 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart AAAAA.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Annual Trading Program.

(2) The designated representative of a CSAPR NO_X Annual source and each CSAPR NO_X Annual unit at the source shall make all submissions required under the CSAPR NO_X Annual Trading Program, except as provided in 40 CFR 97.418. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

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

(2) Any provision of the CSAPR NO_X Annual Trading Program that applies to a CSAPR NO_X Annual unit or the designated representative of a CSAPR NO_X Annual unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

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

(h) Effect on units in Indian country.

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

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

(a) Designated representative requirements.

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

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

(1) The owners and operators, and the designated representative, of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.830 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.831 (initial monitoring system certification and recertification procedures), 97.832 (monitoring system out-of-control periods), 97.833 (notifications concerning monitoring), 97.834 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.835 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.830 through 97.835 shall be used to calculate allocations of CSAPR NO_X Ozone Season Group 2 allowances under 40 CFR 97.811(a)(2) and (b) and 97.812 and to determine compliance with the CSAPR NO_X Ozone Season Group 2 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.830 through 97.835 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) NO_X emissions requirements.

(1) CSAPR NO_X Ozone Season Group 2 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold, in the source's compliance account, CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.824(a) in an amount not less than the tons of total NO_X emissions for such control period from all CSAPR NO_X Ozone Season Group 2 units at the source.

(ii). If total NO_X emissions during a control period in a given year from the CSAPR NO_X Ozone Season Group 2 units at a CSAPR NO_X Ozone Season Group 2 source are in excess of the CSAPR NO_X Ozone Season Group 2 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall hold the CSAPR NOX Ozone Season Group 2 allowances required for deduction under 40 CFR 97.824(d); and

(B). The owners and operators of the source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(2) CSAPR NO_X Ozone Season Group 2 assurance provisions.

(i). If total NO_X emissions during a control period in a given year from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such NO_X emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR NO_X Ozone Season Group 2 allowances available for deduction for such control period under 40 CFR 97.825(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.825(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such NO_X emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such NO_X emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR NO_X Ozone Season Group 2 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total NO_X emissions exceed the sum, for such control period, of the State NO_X Ozone Season Group 2 trading budget under 40 CFR 97.810(a) and the state's variability limit under 40 CFR 97.810(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart EEEEE or of the Clean Air Act if total NO_X emissions from all CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total NO_X emissions from the CSAPR NO_X Ozone Season Group 2 units at CSAPR NO_X Ozone Season Group 2 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR NO_X Ozone Season Group 2 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR NO_X Ozone Season Group 2 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart EEEEE and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(ii). A CSAPR NO_X Ozone Season Group 2 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of May 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.830(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR NOX Ozone Season Group 2 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR NO_X Ozone Season Group 2 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR NO_X Ozone Season Group 2 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR NO_X Ozone Season Group 2 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart EEEEE.

(6) Limited authorization. A CSAPR NO_X Ozone Season Group 2 allowance is a limited authorization to emit one ton of NO_X during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR NO_X Ozone Season Group 2 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart EEEEE, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR NO_X Ozone Season Group 2 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR NO_X Ozone Season Group 2 allowances in accordance with 40 CFR Part 97, Subpart EEEEE.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.830 through 97.835, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.806(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.816 for the designated representative for the source and each CSAPR NO_X Ozone Season Group 2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.816 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart EEEEE.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR NO_X Ozone Season Group 2 Trading Program.

(2) The designated representative of a CSAPR NO_X Ozone Season Group 2 source and each CSAPR NO_X Ozone Season Group 2 unit at the source shall make all submissions required under the CSAPR NO_X Ozone Season Group 2 Trading Program, except as provided in 40 CFR 97.818. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

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

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

(g) Effect on other authorities.

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

(h) Effect on units in Indian country.

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

SECTION III: CSAPR SO_2 Group 1 Trading Program requirements (40 CFR 97.606)

(a) Designated representative requirements.

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

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

(1) The owners and operators, and the designated representative, of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements of 40 CFR 97.630 (general requirements, including installation, certification, and data accounting, compliance deadlines, reporting data, prohibitions, and long-term cold storage), 97.631 (initial monitoring system certification and recertification procedures), 97.632 (monitoring system out-of-control periods), 97.633 (notifications concerning monitoring), 97.634 (recordkeeping and reporting, including monitoring plans, certification applications, quarterly reports, and compliance certification), and 97.635 (petitions for alternatives to monitoring, recordkeeping, or reporting requirements).

(2) The emissions data determined in accordance with 40 CFR 97.630 through 97.635 shall be used to calculate allocations of CSAPR SO_2 Group 1 allowances under 40 CFR 97.611(a)(2) and (b) and 97.612 and to determine compliance with the CSAPR SO_2 Group 1 emissions limitation and assurance provisions under paragraph (c) below, provided that, for each monitoring location from which mass emissions are reported, the mass emissions amount used in calculating such allocations and determining such compliance shall be the mass emissions amount for the monitoring location determined in accordance with 40 CFR 97.630 through 97.635 and rounded to the nearest ton, with any fraction of a ton less than 0.50 being deemed to be zero.

(c) SO_2 emissions requirements.

(1) CSAPR SO_2 Group 1 emissions limitation.

(i). As of the allowance transfer deadline for a control period in a given year, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO2 Group 1 unit at the source shall hold, in the source's compliance account, CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.624(a) in an amount not less than the tons of total SO_2 emissions for such control period from all CSAPR SO_2 Group 1 units at the source.

(ii). If total SO_2 emissions during a control period in a given year from the CSAPR SO_2 Group 1 units at a CSAPR SO_2 Group 1 source are in excess of the CSAPR SO_2 Group 1 emissions limitation set forth in paragraph (c)(1)(i) above, then:

(A). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall hold the CSAPR SO_2 Group 1 allowances required for deduction under 40 CFR 97.624(d); and

(B). The owners and operators of the source and each CSAPR SO_2 Group 1 unit at the source shall pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act, and each ton of such excess emissions and each day of such control period shall constitute a separate violation 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(2) CSAPR SO_2 Group 1 assurance provisions.

(i). If total SO_2 emissions during a control period in a given year from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state exceed the state assurance level, then the owners and operators of such sources and units in each group of one or more sources and units having a common designated representative for such control period, where the common designated representative's share of such SO_2 emissions during such control period exceeds the common designated representative's assurance level for the state and such control period, shall hold (in the assurance account established for the owners and operators of such group) CSAPR SO_2 Group 1 allowances available for deduction for such control period under 40 CFR 97.625(a) in an amount equal to two times the product (rounded to the nearest whole number), as determined by the Administrator in accordance with 40 CFR 97.625(b), of multiplying—

(A). The quotient of the amount by which the common designated representative's share of such SO_2 emissions exceeds the common designated representative's assurance level divided by the sum of the amounts, determined for all common designated representatives for such sources and units in the state and Indian country within the borders of such state for such control period, by which each common designated representative's share of such SO_2 emissions exceeds the respective common designated representative's assurance level; and

(B). The amount by which total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state for such control period exceed the state assurance level.

(ii). The owners and operators shall hold the CSAPR SO_2 Group 1 allowances required under paragraph (c)(2)(i) above, as of midnight of November 1 (if it is a business day), or midnight of the first business day thereafter (if November 1 is not a business day), immediately after such control period.

(iii). Total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period in a given year exceed the state assurance level if such total SO_2 emissions exceed the sum, for such control period, of the state SO_2 Group 1 trading budget under 40 CFR 97.610(a) and the state's variability limit under 40 CFR 97.610(b).

(iv). It shall not be a violation of 40 CFR Part 97, Subpart CCCCC or of the Clean Air Act if total SO_2 emissions from all CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceed the state assurance level or if a common designated representative's share of total SO_2 emissions from the CSAPR SO_2 Group 1 units at CSAPR SO_2 Group 1 sources in the state and Indian country within the borders of such state during a control period exceeds the common designated representative's assurance level.

(v). To the extent the owners and operators fail to hold CSAPR SO_2 Group 1 allowances for a control period in a given year in accordance with paragraphs (c)(2)(i) through (iii) above,

(A). The owners and operators shall pay any fine, penalty, or assessment or comply with any other remedy imposed under the Clean Air Act; and

(B). Each CSAPR SO_2 Group 1 allowance that the owners and operators fail to hold for such control period in accordance with paragraphs (c)(2)(i) through (iii) above and each day of such control period shall constitute a separate violation of 40 CFR Part 97, Subpart CCCCC and the Clean Air Act.

(3) Compliance periods.

(i). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(1) above for the control period starting on the later of January 1, 2015 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(ii). A CSAPR SO_2 Group 1 unit shall be subject to the requirements under paragraph (c)(2) above for the control period starting on the later of January 1, 2017 or the deadline for meeting the unit's monitor certification requirements under 40 CFR 97.630(b) and for each control period thereafter.

(4) Vintage of allowances held for compliance.

(i). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraph (c)(1)(i) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for such control period or a control period in a prior year.

(ii). A CSAPR SO_2 Group 1 allowance held for compliance with the requirements under paragraphs (c)(1)(ii)(A) and (2)(i) through (iii) above for a control period in a given year must be a CSAPR SO_2 Group 1 allowance that was allocated for a control period in a prior year or the control period in the given year or in the immediately following year.

(5) Allowance Management System requirements. Each CSAPR SO_2 Group 1 allowance shall be held in, deducted from, or transferred into, out of, or between Allowance Management System accounts in accordance with 40 CFR Part 97, Subpart CCCCC.

(6) Limited authorization. A CSAPR SO_2 Group 1 allowance is a limited authorization to emit one ton of SO_2 during the control period in one year. Such authorization is limited in its use and duration as follows:

(i). Such authorization shall only be used in accordance with the CSAPR SO_2 Group 1 Trading Program; and

(ii). Notwithstanding any other provision of 40 CFR Part 97, Subpart CCCCC, the Administrator has the authority to terminate or limit the use and duration of such authorization to the extent the Administrator determines is necessary or appropriate to implement any provision of the Clean Air Act.

(7) Property right. A CSAPR SO_2 Group 1 allowance does not constitute a property right.

(d) Title V permit revision requirements.

(1) No title V permit revision shall be required for any allocation, holding, deduction, or transfer of CSAPR SO_2 Group 1 allowances in accordance with 40 CFR Part 97, Subpart CCCCC.

(2) This permit incorporates the CSAPR emissions monitoring, recordkeeping and reporting requirements pursuant to 40 CFR 97.630 through 97.635, and the requirements for a continuous emission monitoring system (pursuant to 40 CFR Part 75, Subparts B and H), an excepted monitoring system (pursuant to 40 CFR Part 75, Appendices D and E), a low mass emissions excepted monitoring methodology (pursuant to 40 CFR 75.19), and an alternative monitoring system (pursuant to 40 CFR Part 75, Subpart E). Therefore, the Description of CSAPR Monitoring Provisions table for units identified in this permit may be added to, or changed, in this title V permit using minor permit modification procedures in accordance with 40 CFR 97.606(d)(2) and 70.7(e)(2)(i)(B) or 71.7(e)(1)(i)(B).

(e) Additional recordkeeping and reporting requirements.

(1) Unless otherwise provided, the owners and operators of each CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall keep on site at the source each of the following documents (in hardcopy or electronic format) for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the Administrator.

(i). The certificate of representation under 40 CFR 97.616 for the designated representative for the source and each CSAPR SO_2 Group 1 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such certificate of representation and documents are superseded because of the submission of a new certificate of representation under 40 CFR 97.616 changing the designated representative.

(ii). All emissions monitoring information, in accordance with 40 CFR Part 97, Subpart CCCCC.

(iii). Copies of all reports, compliance certifications, and other submissions and all records made or required under, or to demonstrate compliance with the requirements of, the CSAPR SO_2 Group 1 Trading Program.

(2) The designated representative of a CSAPR SO_2 Group 1 source and each CSAPR SO_2 Group 1 unit at the source shall make all submissions required under the CSAPR SO_2 Group 1 Trading Program, except as provided in 40 CFR 97.618. This requirement does not change, create an exemption from, or otherwise affect the responsible official submission requirements under a title V operating permit program in 40 CFR Parts 70 and 71.

(f) Liability.

(1) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 source or the designated representative of a CSAPR SO_2 Group 1 source shall also apply to the owners and operators of such source and of the CSAPR SO_2 Group 1 units at the source.

(2) Any provision of the CSAPR SO_2 Group 1 Trading Program that applies to a CSAPR SO_2 Group 1 unit or the designated representative of a CSAPR SO_2 Group 1 unit shall also apply to the owners and operators of such unit.

(g) Effect on other authorities.

No provision of the CSAPR SO_2 Group 1 Trading Program or exemption under 40 CFR 97.605 shall be construed as exempting or excluding the owners and operators, and the designated representative, of a CSAPR SO_2 Group 1 source or CSAPR SO_2 Group 1 unit from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act.

(h) Effect on units in Indian country.

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

Appendix 11-A. System Wide Tonnage Limitations

This Appendix is federally enforceable and was established pursuant to Rule 201(1)(a). Appendix 11-A and Appendix 11-B were originally established in the consent decree settling, "U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" and also pursuant Section 324.5503(b) of the Natural Resources and Environmental Protection Act, 1994 Act 451, as amended, and will remain in effect after termination of the consent decree. Definitions specific to this Appendix may be found in Appendix 1-B: Definitions. **(Act 451, Section 324.5503(b))**

System-Wide Annual NOx Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual NO_x Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual NO_x Tonnage Limitation:
2017 and continuing each calendar year thereafter	6,600

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 98)

- For purposes of calculating the System-Wide Annual NOx Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 100)**

System-Wide Annual SO_2 Tonnage Limitations

The Consumers System, collectively, shall operate so as not to exceed the following System-Wide Annual SO_2 Tonnage Limitations:

For the Calendar Year Specified Below:	System-Wide Annual SO_2 Tonnage Limitation:
2017 and continuing each calendar year thereafter	10,900

("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 129)

- For purposes of calculating the System-Wide Annual SO_2 Tonnage Limitations, Consumers shall use CEMS in accordance with the procedures specified in 40 CFR Part 75, which includes the requirements associated with the concepts of bias adjustments and missing data substitution. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 131)**

Appendix 11-B. Allowance Provisions

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

Use and Surrender of NOx Allowances

- Consumers shall not use NOx Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as provided in this permit, by using, tendering, or otherwise applying NOx Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 101)**

- Except as provided by Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any NOx Allowances allocated to the Consumers System Units. Nothing in the Consent Decree shall restrict Consumers' ability to transfer NOx Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 102)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all NOx Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, NOx Allowances allocated to the Consumers System may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 103)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining NOx Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 104)**

Super-Compliant NOx Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer NOx Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any NOx pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree as provided in this permit, and is not otherwise required by law;
  b. the use of SCR prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for NO_x at the following Units: (i) at Campbell Unit 1: 0.200 lb/MMBTU; (ii) at Campbell Unit 2: 0.070 lb/MMBTU; (iii) at Campbell Unit 3: 0.070 lb/MMBTU;

  provided that Consumers is also in compliance for that calendar year with all emission limitations for NO_x set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014"paragraph 106)**

Method for Surrender of NOx Allowances

- Consumers shall Surrender, or transfer to a non-profit third-party selected by Consumers for Surrender, all NOx Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions by June 30 of the immediately following calendar year. Such Surrender need not include the specific NOx Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders NO_x Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 107)**

- If any NOx Allowances required to be Surrendered under Appendix 11-B: Allowance Provisions are transferred directly to a non-profit third-party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the NOx Allowances and list the serial numbers of the transferred NOx Allowances; and (b) include a certification by the third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the NOx Allowances and will not use any of the NOx Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any NOx Allowances, Consumers shall include a statement that the third-party recipient(s) Surrendered the NOx Allowances for permanent Surrender to USEPA in accordance with the provisions of Appendix 11-B, "Method for Surrender of NOx Allowances," within one year after Consumers transferred the NOx Allowances to them. Consumers shall not have complied with the NOx

Allowance Surrender requirements of Appendix 11-B, "Method for Surrender of NOx Allowances," until all third-party recipient(s) have actually Surrendered the transferred NOx Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 108)**

- For all NOx Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit a NOx Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such NOx Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such NOx Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these NO_x Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the NOx Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 109)**

Use and Surrender of SO_2 Allowances

- Consumers shall not use SO_2 Allowances to comply with any requirement of the Consent Decree, as enumerated in this permit, including by claiming compliance with any emission limitation required by the Consent Decree, as enumerated in this permit, by using, tendering, or otherwise applying SO_2 Allowances to offset any excess emissions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 132)**

- Except as provided in Appendix 11-B: Allowance Provisions, Consumers shall not sell, bank, trade, or transfer any SO_2 Allowances allocated to the Consumers System Units. Nothing in Appendix 11-B: Allowance Provisions, shall restrict Consumers' ability to transfer SO_2 Allowances among its own facility or general accounts. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 133)**

- Beginning with the year 2014 compliance period, and continuing each year thereafter, Consumers shall Surrender all SO_2 Allowances allocated to the Consumers System for that year's compliance period that Consumers does not need in order to meet its own federal and/or state CAA regulatory requirements for the Consumers System Units. However, SO_2 Allowances allocated to the Consumers System Units may be used by Consumers to meet its own federal and/or state CAA regulatory requirements for such Units. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 134)**

- Nothing in Appendix 11-B: Allowance Provisions, shall prevent Consumers from purchasing or otherwise obtaining SO_2 Allowances from another source for purposes of complying with federal and/or state CAA regulatory requirements to the extent otherwise allowed by law. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 135)**

Super-Compliant SO_2 Allowances

- Beginning with the year 2014 and continuing in each calendar year thereafter, Consumers may sell, bank, use, trade, or transfer SO_2 Allowances made available in that year's compliance period solely as a result of:
  a. the installation and operation of any SO_2 pollution control that is not otherwise required by, or necessary to maintain compliance with, any provision of the Consent Decree, and is not otherwise required by law;
  b. the use of FGD or DSI prior to the date established by the Consent Decree; or
  c. achievement and maintenance of an Emission Rate below a 365-Day Rolling Average Emission Rate for SO_2 at the following Units: (i) at Campbell Units 1 and 2: 0.260 lb/MMBTU; (ii) at Campbell Unit 3: 0.060 lb/MMBTU

  provided that Consumers is also in compliance for that calendar year with all emission limitations for SO_2 set forth in the Consent Decree as provided in this permit. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 137)**

Method for Surrender of SO_2 Allowances

- Consumers shall Surrender, or transfer to a non-profit third party selected by Consumers for Surrender, all SO_2 Allowances required to be Surrendered pursuant to Appendix 11-B: Allowance Provisions, by June 30 of the immediately following calendar year. Such Surrender need not include the specific SO_2 Allowances that were allocated to Consumers System Units, so long as Consumers Surrenders SO_2 Allowances that are from the same year or an earlier year and that are equal to the number required to be Surrendered under Appendix 11-B:

Allowance Provisions. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 138)**

- If any SO_2 Allowances required to be Surrendered under Appendix 11-B, "Use and Surrender of SO2 Allowances," are transferred directly to a non-profit third party, Consumers shall include a description of such transfer in the next report submitted to USEPA pursuant to the Periodic Reporting provisions of the Consent Decree (beginning at paragraph 188 of the Consent Decree). Such report shall: (a) identify the non-profit third-party recipient(s) of the SO_2 Allowances and list the serial numbers of the transferred SO_2 Allowances; and (b) include a certification by the non-profit third-party recipient(s) stating that the recipient(s) will not sell, trade, or otherwise exchange any of the allowances and will not use any of the SO_2 Allowances to meet any obligation imposed by any environmental law. No later than the third periodic report due after the transfer of any SO_2 Allowances, Consumers shall include a statement that the non-profit third-party recipient(s) Surrendered the SO_2 Allowances for permanent Surrender to USEPA in accordance with the provisions of the following Paragraph 140 Appendix 11-B, "Method for Surrender of SO2 Allowances," within one year after Consumers transferred the SO_2 Allowances to them. Consumers shall not have complied with the SO_2 Allowance Surrender requirements of this Appendix 11-B, "Method for Surrender of SO2 Allowances," until all third-party recipient(s) have actually Surrendered the transferred SO_2 Allowances to USEPA. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 139)**
- For all SO_2 Allowances required to be Surrendered, Consumers or the third-party recipient(s) (as the case may be) shall first submit an SO_2 Allowance transfer request to USEPA's Office of Air and Radiation's Clean Air Markets Division directing the transfer of such SO_2 Allowances to the USEPA Enforcement Surrender Account or to any other USEPA account that USEPA may direct in writing. Such SO_2 Allowance transfer requests may be made in an electronic manner using USEPA's Clean Air Markets Division Business System or similar system provided by USEPA. As part of submitting these transfer requests, Consumers or the third-party recipient(s) shall irrevocably authorize the transfer of these SO_2 Allowances and identify – by name of account and any applicable serial or other identification numbers or station names – the source and location of the SO_2 Allowances being Surrendered. **("U.S. v Consumers Energy Company, Civil Action 14-13580, E.D. Mich., 2014" paragraph 140)**

Attachment F

Case 21090 Kapala Direct Testimony

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

REVISED DIRECT TESTIMONY

OF

NORMAN J. KAPALA

ON BEHALF OF

CONSUMERS ENERGY COMPANY

October 2021

Q. Please state your name and business address.

A. My name is Norman J. Kapala, and my business address is One Energy Plaza, Jackson, Michigan 49201.

Q. By whom are you employed and in what capacity?

A. I am employed by Consumers Energy Company ("Consumers Energy" or the "Company") as Executive Director of Fossil and Renewable Generation.

Q. What is your formal education experience?

A. In 1996, I received a Bachelor of Science in Mechanical Engineering from Michigan Technological University. In 2008, I received a Master of Science in Manufacturing Management from Kettering University.

Q. Please describe your business experience.

A. From 1990 to 1994, I served our country as a Rifleman in the United States Marine Corps. In May 1996, I joined Chrysler Corporation and held various positions with progressing levels of responsibility at the Trenton Engine Plant, progressing from a Technical Advisor to Area Manager. In September 2002, I joined Delphi Corporation as a Production Supervisor and, in September 2004, progressed to a Senior Manufacturing Engineer. In July 2008, I joined Consumers Energy at the D.E. Karn ("Karn")/ J.C. Weadock ("Weadock") Generating Complex and progressed through positions from Senior Engineer to the Site Business Manager. In June 2015, I transferred to the B.C. Cobb ("Cobb") Generating Complex and J.H. Campbell ("Campbell") Generating Complex as the Site Business Manager for both facilities. Following the closure of seven of the Company's coal-fired units at its Cobb, Weadock, and J.R. Whiting ("Whiting") sites (collectively, the "Classic 7") in 2016, I was promoted to Executive Director of Coal Generation. In April

2020, I was appointed to the position of Executive Director of Fossil and Renewable Generation with operations and maintenance responsibility for Coal, Gas, Wind, and Solar Generation.

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

A. Yes. I sponsored testimony in the following MPSC cases:

Case No. U-20165	2018 Integrated Resource Plan under MCL 460.6t;
Case No. U-20202	2018 Power Supply Cost Recovery ("PSCR") Reconciliation;
Case No. U-20219	2019 PSCR Plan;
Case No. U-20220	2019 PSCR Reconciliation;
Case No. U-20525	2020 PSCR Plan;
Case No. U-20844	Ludington Depreciation Case;
Case No. U-20802	2021 PSCR Plan; and
Case No. U-20526	2020 PSCR Reconciliation.

Q. What is the purpose of your direct testimony in this proceeding?

A. My direct testimony will address: (i) a description of Consumers Energy's existing generation resources; (ii) the Company's projected capital expenditures and Operations and Maintenance ("O&M") expenses for its existing generation fleet, as those costs were represented in Consumers Energy's Integrated Resource Plan ("IRP") modeling; (iii) the Company's projected capital expenditures and O&M expenses for the Covert combined cycle gas plant ("Covert"), the Dearborn Industrial Generation combined cycle and peaking units ("DIG"), the Kalamazoo River Generating Station peaking plant ("Kalamazoo"), and the Livingston Generating Station peaking plant ("Livingston") that are included in the Company's Proposed Course of Action ("PCA"); (iv) the Company's projected separation

activity costs related to the early retirement of its existing generating units at the Campbell and Karn generating sites; (v) Consumers Energy's avoidable and incremental capital expenditures and expenses in different cases involving the early retirement of Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4; (vi) the performance of the Company's existing generation fleet; (vii) execution risks faced by Consumers Energy if Campbell Units 1, 2, or 1 and 2, Campbell Unit 3, or Karn Units 3 and 4 are selected for early retirement; and (viii) the tax, community, and employee impacts of an early retirement case.

Q. What is the Company's retirement recommendation with respect to Campbell Units 1 and 2, Campbell Unit 3, and Karn Units 3 and 4?

A. As discussed by several Company witnesses, and as also further explained in my direct testimony, Consumers Energy's PCA proposes to retire Karn Units 3 and 4 in 2023, and retire Campbell Units 1, 2, and 3 in 2025. As discussed in Section II of my testimony, this PCA will result in $75,648,000 in avoided capital expenditures, $15,645,00 in avoided unit separation capital expenditures, and $10,050,000 in avoided major maintenance expenses at Karn Units 3 and 4 compared to the Company's base case outlook ("base case"). In addition, this PCA will result in $~~190,613,000~~136,244,000 in avoided capital expenditures, $64,146,000 in avoided unit separation capital expenditures, and $57,555,000 in avoided major maintenance expenses at Campbell Unit 3; $12,114,000 in avoided capital expenditures and $61,524,000 in avoided major maintenance expenses at Campbell Unit 1; and $13,385,000 in avoided capital expenditures and $84,186,000 in avoided major maintenance expenses at Campbell Unit 2, compared to the Company's base case

assumptions of continued operations to the units current design lives in each of the scenarios described by Company witness Sara T. Walz.

Q. Are there any offsets to the avoided cost numbers?

A. Yes. The avoided capital expenditures, avoided unit separation capital expenditures, and avoided major maintenance expenses would be partially offset by the capital expenditures and O&M expenses for the Covert, DIG, Kalamazoo, and Livingston gas generating plants (collectively "new gas plants") which are discussed in Section III of my direct testimony. The Company is also projecting that it will incur approximately $60,000,000 in employee retention and separation activity expenses, as discussed in Section VIII of my direct testimony; however, the Company does not consider these costs incremental in nature as the Company would have incurred these costs at a later date had an early retirement not occurred.

Q. Are you sponsoring any exhibits with your direct testimony?

A. Yes. I am sponsoring the following exhibits:

Exhibit A-50 (NJK-1) Revised	Summary of Capital Expenditures and Operations and Maintenance Expenses;
Exhibit A-51 (NJK-2) Revised	Summary of Projected Generation Operations Capital Expenditures;
Exhibit A-52 (NJK-3)	Summary of Projected Generation Operations Major Maintenance Expenses;
Exhibit A-53 (NJK-4)	Summary of Projected Generation Operations Base O&M Expenses;
Exhibit A-54 (NJK-5)	Generation Operations – Summary of Capital Expenditures and Costs of Removal;

Exhibit A-55 (NJK-6) Revised	Summary of Projected Generation Operations Capital Expenditures and Operations and Maintenance Expenses – new gas plants;
Exhibit A-56 (NJK-7)	Summary of Projected Generation Operations Separation Activity Capital Expenditures;
Exhibit A-57 (NJK-8) Revised	Generation Capital Expenses – Avoidable And Incremental Under an Early Retirement Case 2024 - 2032;
Exhibit A-58 (NJK-9)	Generation Major Maintenance Expenses – Avoidable Under An Early Retirement Case 2024-2032;
Exhibit A-59 (NJK-10)	Generating Unit Random Outage Rates; and
Confidential Exhibit A-60 (NJK-11)	Generating Unit Heat Rates.

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

A. Yes.

SECTION I: EXISTING GENERATION RESOURCES

Q. Please provide an overview of the Company's non-renewable energy generation assets.

A. As of 2020, the Company's total non-renewable owned generation assets had a net demonstrated summer operating capability of 5,292 MW, comprised of the following coal-, oil-, or gas-fired; hydroelectric; and pumped storage facility units:

TABLE 1

RESOURCE	MICHIGAN LOCATION	IN-SERVICE DATE	AGE (years)	RETIREMENT DATE	REMAINING EST. TIME OF OPERATION (years)	LICENSING STATUS	NET GENERATING CAPABILITY (MW)
COAL FIRED							
JH Campbell 1	West Olive, MI	1962	59	2031	10	Active	260
JH Campbell 2	West Olive, MI	1967	54	2031	10	Active	260
JH Campbell 3	West Olive, MI	1980	41	2039	18	Active	785 (owned share)
DE Karn 1	Essexville, MI	1959	62	2023	2	Active	255
DE Karn 2	Essexville, MI	1961	60	2023	2	Active	258
OIL OR GAS FIRED							
DE Karn 3	Essexville, MI	1975	46	2031	10	Active	362
DE Karn 4	Essexville, MI	1977	44	2031	10	Active	362
Zeeland CC	Zeeland, MI	2002	19	2041	20	Active	575
Zeeland 1A	Zeeland, MI	2002	19	2041	20	Active	180
Zeeland 1B	Zeeland, MI	2002	19	2041	20	Active	180
Jackson	Jackson, MI	2002	19	2041	20	Active	547
HYDROELECTRIC							
Alcona	Alcona County, MI	1924	97	n/a	n/a	Active	8
Allegan	Allegan County, MI	1936	85	n/a	n/a	Active	3
Cooke	Iosco County, MI	1911	110	n/a	n/a	Active	9
Croton	Newaygo County, MI	1907	114	n/a	n/a	Active	9
Five Channels	Iosco County, MI	1912	109	n/a	n/a	Active	6
Foote	Iosco County, MI	1918	103	n/a	n/a	Active	9
Hardy	Newaygo County, MI	1931	90	n/a	n/a	Active	30
Hodenpyl	Wexford County, MI	1925	96	n/a	n/a	Active	17
Loud	Iosco County, MI	1913	108	n/a	n/a	Active	4
Mio	Oscoda County, MI	1916	105	n/a	n/a	Active	5
Rogers	Mecosta County, MI	1906	115	n/a	n/a	Active	7
Tippy	Manistee County, MI	1918	103	n/a	n/a	Active	21
Webber	Ionia County, MI	1907	114	n/a	n/a	Active	3
ENERGY STORAGE							
Ludington Units 1-6	Ludington, MI	1973	48	2069	48	Active	1138 (owned share)

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

A. The Company owns approximately 93% of Campbell Unit 3. Michigan Public Power Agency and Wolverine Power Supply Cooperative, Inc. own the remaining 7%. Thus, the 785 MW capacity reported is 93% of the Campbell Unit 3 net demonstrated summer operating capability, reflecting the Company's share of ownership.

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

A. The Company owns 51% of the Ludington Plant and DTE Electric Company owns the remaining 49%. Thus, the 1,138 MW capacity reported is 51% of the total Ludington Plant net demonstrated summer operating capability, reflecting the Company's share of ownership.

SECTION II: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-50 (NJK-1) Revised.

A. Exhibit A-50 (NJK-1) Revised shows the projected capital expenditures and major maintenance expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the period of January 1, 2020 through May 31, 2031, and the base O&M expenses for the Campbell Units 1, 2, and 3; Karn Units 1 and 2; and Karn Units 3 and 4 for the same period, under a variety of cases. These are the costs and the date range that the Company used for modeling purposes in this IRP. The Company evaluated a base case, in which all four units (Karn Units 3 and 4 and Campbell Units 1 and 2) retire on May 31, 2031, and then evaluated sixteen early retirement cases related to the Karn and Campbell sites:

- Retirement of Karn Units 3 and 4 on May 31, 2023;
- Retirement of Karn Units 3 and 4 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2025;
- Retirement of Campbell Unit 3 on May 31, 2032;
- Retirement of Campbell Unit 1 on May 31, 2024;
- Retirement of Campbell Unit 1 on May 31, 2025;

- Retirement of Campbell Unit 1 on May 31, 2026;
- Retirement of Campbell Unit 1 on May 31, 2028;
- Retirement of Campbell Unit 2 on May 31, 2024;
- Retirement of Campbell Unit 2 on May 31, 2025;
- Retirement of Campbell Unit 2 on May 31, 2026;
- Retirement of Campbell Unit 2 on May 31, 2028;
- Retirement of Campbell Units 1 and 2 on May 31, 2024;
- Retirement of Campbell Units 1 and 2 on May 31, 2025;
- Retirement of Campbell Units 1 and 2 on May 31, 2026; and
- Retirement of Campbell Units 1 and 2 on May 31, 2028.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 1 and 2.

A. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, presents the total capital expenditures projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the capital expenditure amounts presented for each unit in each case is a total of all capital expenditures for the period of January 1, 2020 through May 31, 2031. The capital expenditure amounts for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the sixteen early retirement cases, the exhibit presents both the total capital expenditures (including unit separation) over that period that would be made in each respective case and the difference in capital expenditures over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and 3 reflects the early retirement cases for Karn Units 3 and 4; for these cases, the capital expenditures for Karn Units 3 and 4 are reduced versus those shown in the base case. As shown in Exhibit A-50 (NJK-1) Revised, page 1, lines 2 and

3, columns (b) and (c), the 2023 retirement case results in both reduced capital expenditures and also reduced separation costs at Karn Units 3 and 4, and the 2025 retirement case results in reduced capital expenditures at Karn Units 3 and 4, which will be discussed later in my direct testimony. Likewise, Exhibit A-50 (NJK-1) Revised, page 1, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, both the capital expenditures and separation costs for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 1-2, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 1 and 2, lines 6 through 13, columns (c) and (d), shows the reduced or incremental costs for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c) and (d), show reduced costs at Campbell Units 1 and 2 when both units retire. No incremental costs are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Costs of removal are not included in any of the cases in Exhibit A-50 (NJK-1) Revised, page 1, nor are environmental costs related to Steam Electric Effluent Guidelines ("SEEG") and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Heather A. Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 3 and 4.

A. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, presents the total major maintenance expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the major maintenance expenses presented for each unit in each case is a total of all major

maintenance expenses for the period of January 1, 2020 through May 31, 2031. The major maintenance expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total major maintenance expenses over that period that would be made in each respective case, and the difference in major maintenance expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 3, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the major maintenance expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 3, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the major maintenance expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, lines 6 through 13, columns (c) and (d), shows the reduced major maintenance expenses for Campbell Units 1 and 2 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17 columns (c) and (d), shows reduced costs at Campbell Units 1 and 2 when both units retire. No incremental major maintenance expenses are projected at Campbell Unit 3 versus the base case for the cases in which Campbell Units 1 and 2 both retire. Exhibit A-50 (NJK-1) Revised, pages 3 and 4, does not include environmental costs related to SEEG and Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-50 (NJK-1) Revised, pages 5 and 6.

A. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, presents the total O&M expenses projected to be made at the Karn and Campbell sites by the Company in each of the sixteen cases listed above. With the exception of Campbell Unit 3, the O&M expenses presented for each unit in each case is a total of all O&M expenses for the period of January 1, 2020 through May 31, 2031. The O&M expenses for Campbell Unit 3 reflect projected amounts through May 31, 2039. For each of the 16 early retirement cases, the exhibit presents both the total O&M expenses over that period that would be made in each respective case and the difference in O&M expenses over that period relative to the base case. Exhibit A-50 (NJK-1) Revised, page 5, lines 2 and 3, reflects the early retirement cases for Karn Units 3 and 4; for these cases, the O&M expenses for Karn Units 3 and 4 are reduced from those shown in the base case. Likewise, Exhibit A-50 (NJK-1) Revised, page 5, lines 4 and 5, reflects the early retirement cases for Campbell Unit 3; for each of these cases, the O&M expenses for Campbell Unit 3 are also reduced from those shown in the base case. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 17, reflects the retirement cases for which Campbell Unit 1 retires, Campbell Unit 2 retires, or both Campbell Units 1 and 2 retire. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 6 through 9, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 1 retirement and increased O&M expenses for Campbell Units 2 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, pages 5 and 6, lines 10 through 13, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Unit 2 retirement and increased O&M expenses for Campbell Units 1 and 3 versus the base case for the individual unit retirements. Exhibit A-50 (NJK-1) Revised, page 2, lines 14 through 17, columns (c), (d), and (e), shows the reduced O&M expenses for Campbell Units 1 and 2 when both units

retire and increased O&M expenses for Campbell Unit 3. Exhibit A-50 (NJK-1) Revised, pages 5 and 6 do not include environmental costs related to SEEGand Clean Water Act Section 316(b) ("316(b)"). Those environmental costs are discussed by Company witness Breining.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 1.

A. Exhibit A-51 (NJK-2) Revised, page 1, shows the Company's projected capital expenditures for the Company's generating units at the Campbell and Karn sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case retirement case. In this case, Karn Units 1 and 2 retire on May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire on May 31, 2031, and Campbell Unit 3 retires on May 31, 2039.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1?

A. The capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 2?

A. In 2021, the Company projects to spend:

- $2,859,236 at Karn Units 1 and 2, covering seventeen projects, none of which exceed $500,000;
- $4,172,000 at Karn Units 3 and 4, including:
  - Auxiliary Boiler System Optimization ($2,000,000);
  - Replace House Service Water Screen Drives ($950,000); and
  - Twenty-seven additional projects totaling $1,222,000, with no individual project exceeding $300,000;

- $3,493,440 at Campbell Unit 1, including:
  - Re-align 4160V switchgear with Air Quality Control System ("AQCS") implementation ($1,000,000); and
  - Eleven additional projects totaling $2,493,440, with no individual project exceeding $696,000;
- $13,512,160 at Campbell Unit 2, including:
  - Low Pressure Turbine Overhaul ($3,500,000);
  - Secondary Air Heater Basket and Seal Replacement ($1,750,000);
  - Pulse Jet Fabric Filter ("PJFF") Bag Replacement ($2,394,000); and
  - Seventeen additional projects totaling $5,868,160, with no individual project exceeding $858,100; and
- $19,576,382 at Campbell Unit 3, including:
  - Selective Catalytic Reduction ("SCR") Reactor Catalyst Management ($1,959,510);
  - Replace CO-O2 Monitors ($1,044,600);
  - Mill Complete Overhauls ($1,235,000);
  - Reheater Sootblower ($1,250,000);
  - Sootblowing Air Upgrade ($1,200,000);
  - Replace Lake Michigan Intake Screens ($1,339,000);
  - Cell Construction and Permitting ($5,482,830); and
  - Twenty-two additional projects totaling $6,06,442, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 3?

A. In 2022, the Company projects to spend

- $2,135,136 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $350,000;

- $15,416,000 at Karn Units 3 and 4, including:
  - Tank Farm Storage Tank Heating Lines ($1,400,000);
  - Karn Sync Wire Replacement ($1,320,000);
  - Auxiliary Boiler System Optimization ($1,160,000);
  - Parking Lot Replacement ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($3,000,000);
  - Karn 3 Cooling Tower Rebuild ($2,500,000); and
  - Twenty-two additional projects totaling $5,036,000, with no individual project exceeding $450,000;
- $7,300,000 at Campbell Unit 1, including:
  - PJFF Bag Replacement ($1,578,000);
  - Superheat Outlet Pendant – partial replacement ($3,490,000); and
  - Five additional projects totaling $2,232,000, with no individual project exceeding $750,000;
- $5,256,500 at Campbell Unit 2, including:
  - Catalyst Management ($1,120,000);
  - Replace Burner Assemblies ($1,350,000); and
  - Six additional projects totaling $2,786,500, with no individual project exceeding $836,500; and
- $17,125,333 at Campbell Unit 3, including:
  - PJFF Bag & Cleaning Air Manifold Replacement ($3,994,601);
  - SCR Reactor Catalyst Management ($1,866,200);
  - Complete Mill Overhauls ($1,264,800);
  - Replace CO-O2 Monitors ($967,400);
  - Design and Install New Large Particle Ash Screen ($1,485,100);
  - Fuel Handling & Infrastructure Repairs ($1,500,000); and

- Sixteen additional projects totaling $6,047,032, with no individual project exceeding $889,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 4?

A. In 2023, the Company projects to spend:

- $1,123,678 at Karn Units 1 and 2, covering 12 projects, none of which exceeds $235,136;
- $10,072,000 at Karn Units 3 and 4, including:
  - Distributed Control System Evergreen Project ($1,000,000);
  - Karn 3 Ductwork Expansion Joint Replacement ($1,000,000);
  - Karn 3 Cooling Tower Rebuild ($4,800,000);
  - Capital Equipment Repairs ($1,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $7,214,680 at Campbell Unit 1, including:
  - PJFF Filter Bag Replacement ($1,514,100);
  - Replace Air Preheater Baskets and Seals ($1,113,400);
  - Distributed Control System and Simulator Upgrade ($1,500,000);
  - Ashpit Rebuild ($1,000,000); and
  - Twelve additional projects totaling $2,087,180, with no individual project exceeding $750,000;
- $9,472,020 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($5,053,000);
  - SCR Reactor Catalyst Replacement ($2,000,000); and
  - Nine additional projects totaling $2,419,020, with no individual project exceeding $750,000; and
- $~~20,766,757~~20,478,187 at Campbell Unit 3, including:

- PJFF Bag & Cleaning Air Manifold Replacement ($3,263,331);
- Complete Mill Overhauls ($1,295,300);
- Design and Install New Large Particle Ash Screen ($1,008,700);
- Secondary Air Heater basket & seal replacement ($2,425,000)
- High Pressure Feedwater Heater 8A replacement ($5,039,800);
- Fuel Handling & Infrastructure Repairs ($1,500,000); and
- ~~Eighteen~~ Seventeen additional projects totaling $~~7,242,827~~6,954,257, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 5?

A. In 2024, the Company projects to spend:

- $9,775,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($800,000);
  - Karn 3 Cooling Tower Rebuild ($4,950,000);
  - Capital Equipment Repairs ($3,000,000); and
  - Twelve additional projects totaling $2,272,000, with no individual project exceeding $758,000;
- $9,753,000 at Campbell Unit 1 including:
  - Replace Burners Corner 1-8 ($2,700,000);
  - Replace Air Preheater Baskets and Seals ($1,137,100);
  - Boiler Component Replacement ($3,000,000);
  - Balance of Plant Equipment Replacement ($1,500,000) and
  - Six additional projects totaling $1,415,900, with no individual project exceeding $815,900;
- $11,252,000 at Campbell Unit 2, including:
  - Horizontal Reheat Replacement ($7,952,000);

- Distributed Control System and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $1,800,000, with no individual project exceeding $750,000; and

- $~~35,780,799~~33,395,569 at Campbell Unit 3, including:
  - SCR Reactor Catalyst Management ($1,959,510);
  - Turbine Drain Modifications ($2,535,000);
  - Superheat Terminal Drain Replacement ($3,023,100);
  - Replace Boiler Sidewall Panels ($2,425,000);
  - Replace Boiler Front And Rear Wall Panels ($2,482,900);
  - Secondary Air Heater basket & seal replacement ($1,562,000);
  - Fuel Handling & Infrastructure Repairs ($1,500,000);
  - ~~Dry Ash Landfill Closure ($1,635,230);~~
  - Cell Construction and Permitting ($5,482,830); and
  - ~~Twenty-two~~Twenty-one additional projects totaling $~~10,600,029~~12,425,229, with no individual project exceeding $933,100.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 6?

A. In 2025, the Company projects to spend:

- $10,134,000 at Karn Units 3 and 4, including:
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($2,500,000);
  - Karn 3 Cooling Tower Rebuild ($2,565,000);
  - Capital Replacements ($4,000,000); and
  - Three additional projects totaling $1,069,000, with no individual project exceeding $750,000;
- $2,550,000 at Campbell Unit 1, including four projects that do not exceed $669,000 individually; and

- $7,800,000 at Campbell Unit 2, including:
  - Replace turbine right side Reheat Stop Valve body ($1,850,000); and
  - Boiler Component Replacement ($3,000,000);
- Five additional projects totaling $2,950,000, with no individual project exceeding $750,000; and
- $~~30,179,045~~14,512,045 at Campbell Unit 3, including:
  - GSU Replacement ($6,485,045);
  - SCR Reactor Catalyst Management ($3,000,000);
  - AQCS Equipment repair/replacement ($1,000,000);
  - ~~Part 115 JH Campbell B-K landfill cap ($15,667,000)~~
  - Cell Construction and Permitting ($2,000,000); and
  - Four additional projects totaling $2,027,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, line 7?

A. In 2026, the Company projects to spend:

- $9,900,000 at Karn Units 3 and 4, including:
  - Karn 3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($4,000,000);
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($3,000,000);
  - Capital Replacements ($2,000,000); and
  - Three additional projects totaling $6,050,000, with no individual project exceeding $250,000;
- $3,300,000 at Campbell Unit 1, including five projects that do not exceed $750,000 individually;
- $4,420,000 at Campbell Unit 2, including:

- Catalyst Management ($1,120,000); and
- Five additional projects totaling $3,300,000, with no individual project exceeding $750,000; and

- $~~29,053,000~~4,400,000 at Campbell Unit 3, including:
  - ~~Replace Air and Flue Gas Expansion Joints ($2,000,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,653,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000.

Q. What is the basis for the projected capital expenditures in Exhibit A-51 (NJK-2) Revised, page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, as shown in Exhibit A-51 (NJK-2) Revised, page 1. The capital projects for Karn Units 3 and 4 are as follows:

- 2027: Four projects totaling $8,950,000, which includes:
  - K3 Ductwork Replace Insulation & Lagging - ID Fan to Stack ($2,600,000);
  - Karn 3 Distributed Control System ("DCS") & Simulator Evergreen ($1,000,000);
  - Karn 4 DCS & Simulator Evergreen ($1,350,000); and
  - Karn 4 Ductwork Replace Insulation & Lagging - Boiler to Stack ($4,000,000);
- 2028-2029: One project each year totaling $2,000,000, for capital replacements;
- 2030: One project totaling $1,000,000, for capital replacements; and
- 2031: One project totaling $500,000, for capital replacements.

The capital projects for Campbell Unit 1 are as follows:

- 2027: Five projects totaling $4,050,000, which include:

- DCS and Simulator Upgrade ($1,500,000); and
- Four additional projects totaling $2,550,000, with no individual project exceeding $750,000;

- 2028: Four projects totaling $3,500,000, which include:
  - Fuel Handling and Infrastructure Replacements ($1,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Two additional projects totaling $1,500,000, with no individual project exceeding $750,000;
- 2029: Five projects totaling $3,878,000, which includes:
  - PJFF Filter Bag Replacement ($1,578,000);
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,300,000, with no individual project exceeding $500,000;
- 2030: Five projects totaling $2,563,000, which include:
  - PJFF Filter Bag Replacement ($1,513,600); and
  - Four additional projects totaling $1,050,000, with no individual project exceeding $300,000; and
- 2031: One Project totaling $250,000.

The capital projects for Campbell Unit 2 are as follows:

- 2027: Eight projects totaling $6,845,000, which include:
  - Catalyst Management ($2,806,000);
  - PJFF bag replacement ($1,389,000); and
  - Six projects totaling $2,650,000 with no individual project which exceeds $750,000;
- 2028: Six projects totaling $7,394,000, which include;
  - DCS and Simulator Upgrade ($1,500,000);
  - PJFF bag replacement ($1,389,000);

- Fuel Handling and Infrastructure Replacements ($1,000,000);
- AQCS Equipment repair/replacement ($1,000,000); and
- Two projects totaling $1,500,000 with no individual project which exceeds $500,000;

- 2029: Five projects totaling $2,500,000, which include;
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Four projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four projects totaling $1,050,000, with no individual project which exceeds $300,000; and
- 2031: One project totaling $250,000.

The capital projects for Campbell Unit 3 are as follows:

- 2027: ~~Six~~ Five projects totaling $~~30,563,600~~5,900,000, including:
  - ~~Cell Construction and Permitting ($3,500,000);~~
  - ~~Part 115 JH Campbell B-K landfill cap ($24,663,000);~~ and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2028: Five projects totaling $4,400,000, including:
  - SCR Reactor Catalyst Management ($2,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2029: Six projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment repair/replacement ($2,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;

- 2030: ~~Four~~ Five projects totaling $~~4,650,000~~11,150,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000);
  - Cell Construction and Permitting ($6,500,000);
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2031: Four projects totaling $2,400,000, with no individual project which exceeds $750,000;
- 2032: Four projects totaling $2,750,000, which include:
  - AQCS Equipment repair/replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2033: Seven projects totaling $11,750,000, which include:
  - SCR Reactor Catalyst Management ($2,000,000);
  - Replace Air and Flue Gas Expansion Joints ($2,000,000);
  - Boiler Component Replacement ($5,000,000);
  - AQCS Equipment Repair/Replacement ($1,000,000); and
  - Three additional projects totaling $1,750,000, with no individual project exceeding $750,000;
- 2034: Five projects totaling $5,400,000, which include:
  - SCR Reactor Catalyst Management ($3,000,000); and
  - Four additional projects totaling $2,400,000, with no individual project exceeding $750,000;
- 2035: Five~~our~~ projects totaling $~~3,650,000~~10,150,000, which include:
  - AQCS Equipment repair/replacement ($2,000,000);
  - Cell Construction and Permitting ($6,500,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;

- 2036: Four projects totaling $4,650,000, which include:
  - AQCS Equipment repair/replacement ($3,000,000); and
  - Three additional projects totaling $1,650,000, with no individual project exceeding $750,000;
- 2037: Four projects totaling $2,400,000, with no individual project which exceeds $750,000; and
- 2038: Two projects totaling $550,600, with no individual project which exceeds $300,000.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 2.

A. Exhibit A-51 (NJK-2) Revised, page 2, shows the Company's projected capital expenditures for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. As shown in Exhibit A-51 (NJK-2) Revised, page 2, column (c), there are no projected incremental capital expenditures for Karn Units 1 and 2 in these cases, which are discussed later in my direct testimony. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 2, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (d), shows that the Company would avoid $75,648,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-51 (NJK-2) Revised, page 2, line 13, column (i), shows that the Company would avoid $62,987,000 in capital expenditures if Karn Units 3 and 4 are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 2, line 13, columns (e) and (j), shows that the Company would avoid $15,465,000 in unit separation capital expenditures and $9,161,000 in unit separation

capital expenditures if Karn Units 3 and 4 are retired on May 31, 2023 and May 31, 2025 respectively.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 3.

A. Exhibit A-51 (NJK-2) Revised, page 3, shows the Company's projected capital expenditures for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025 or on May 31, 2032. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-51 (NJK-2) Revised, page 3, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (c) and (d), show that the Company would avoid $190,613,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 3, line 21, columns (g) and (h), shows that the Company would avoid $31,400,000 in capital expenditures and $64,146,000 in unit separation capital expenditures if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-51 (NJK-2) Revised, page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 4.

A. Exhibit A-51 (NJK-2) Revised, page 4, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 4, also shows the difference in capital expenditures

for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (d) and (e), shows that the Company would avoid $42,840,000 in capital expenditures if Campbell Unit 1 is retired on May 31, 2024 and Campbell Unit 2 would incur incremental capital expenditures of $253,000. Exhibit A-51 (NJK-2) Revised, page 4, line 13, columns (i) and (j), show that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and incur no incremental capital expenditures at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 5.

A. Exhibit A-51 (NJK-2) Revised, page 5, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 5, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 5,

line 13, columns (d) and (e), shows that the Company would avoid $56,070,000 in capital expenditures if Campbell Unit 2 is retired on May 31, 2024, and Campbell Unit 1 would incur incremental capital expenditures of $322,000. Exhibit A-51 (NJK-2) Revised, page 5, line 13, columns (i) and (j), shows that the Company would avoid $46,573,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (d) and (e), shows that the Company would avoid $45,273,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 4, line 26, columns (i) and (j), shows that the Company would avoid $18,333,000 in capital expenditures at Campbell Unit 2 and incur no incremental capital expenditures at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures as it is assumed that unit separation capital expenditures reflected in the base case are not avoided.

Q. Please explain Exhibit A-51 (NJK-2) Revised, page 6.

A. Exhibit A-51 (NJK-2) Revised, page 6, shows the Company's projected capital expenditures for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected capital expenditures are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-51 (NJK-2) Revised, page 6, also shows the difference in capital expenditures for each calendar year relative to the base case. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (d) and (e), shows that the Company would avoid

$42,840,000 in capital expenditures at Campbell Unit 1 and $56,070,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-51 (NJK-2) Revised, page 6, line 13, columns (i) and (j), shows that the Company would avoid $35,951,000 in capital expenditures at Campbell Unit 1 and $46,573,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (d) and (e), shows that the Company would avoid $34,046,000 in capital expenditures at Campbell Unit 1 and $45,273,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-51 (NJK-2) Revised, page 6, line 26, columns (i) and (j), shows that the Company would avoid $14,442,000 in capital expenditures at Campbell Unit 1 and $18,333,000 in capital expenditures at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-51 (NJK-2) Revised, page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 capital expenditures because the unit separation capital expenditures reflected in the base case are not avoided.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1?

A. The major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 1, are those that were used for 2020 in the Company's IRP modeling.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 2?

A. In 2021, the Company projects to spend:

- $3,771,000 at Karn Units 1 and 2, covering 21 projects, none of which exceeds $700,000;

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $11,930,200 at Campbell Units 1 and 2 including:
  - Campbell 2 Generator Overhaul-Rewedge-Collector Ring Replacement ($3,630,000);
  - Campbell 2 Turbine Inspection and Overhaul ($2,370,000);
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,512,000); and
  - Twenty-two additional projects totaling $4,418,200, with no individual project exceeding $750,000; and
- $5,102,729 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000); and
  - Twenty-two additional projects totaling $3,902,729, with no individual project exceeding $715,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 3?

A. In 2022, the Company projects to spend:

- $3,292,000 at Karn Units 1 and 2, covering 19 projects, none of which exceeds $700,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,537,000 at Campbell Units 1 and 2 including:
  - Campbell 1 and 2 Periodic Outage Maintenance ($1,248,000); and
  - Thirteen additional projects totaling $2,289,000, with no individual project exceeding $600,000; and
- $4,208,040 at Campbell Unit 3 including:
  - Boiler Feed Pump Turbine Inspection ($1,680,000); and
  - Fourteen additional projects totaling $2,528,040, with no individual project exceeding $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 4?

A. In 2023, the Company projects to spend:

- $826,000 at Karn Units 1 and 2, covering seven projects, none of which exceeds $200,000;
- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $2,905,000 at Campbell Units 1 and 2 covering 10 projects, none of which exceeds $643,667; and
- $2,523,970 at Campbell Unit 3 covering 12 projects, none of which exceeds $425,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 5?

A. In 2024, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $3,405,167 at Campbell Units 1 and 2 covering 12 projects, none of which exceeds $655,167; and
- $12,954,250 at Campbell Unit 3 including:
  - Campbell 3 Turbine Overhaul ($7,931,350);
  - Campbell 3 Boiler Chemical Cleaning ($1,429,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,000,000);
  - Campbell 3 Periodic Outage Maintenance ($933,100); and
  - Eight additional projects totaling $1,660,800, with no individual project exceeding $430,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 6?

A. In 2025, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceeds $250,000;
- $4,569,000 at Campbell Units 1 and 2 including:
  - Campbell 2 Turbine Valve Inspection ($1,300,000); and
  - Seven additional projects totaling $3,269,000, with no individual project exceeding $666,667; and
- $3,810,600 at Campbell Unit 3 including:
  - Campbell 3 Turbine Valve Inspection ($1,200,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six additional projects totaling $1,410,600, with no individual project exceeding $450,000.

Q. What is the basis for the projected major maintenance expenses in Exhibit A-52 (NJK-3), page 1, line 7?

A. In 2026, the Company projects to spend:

- $1,000,000 at Karn Units 3 and 4, covering seven projects, none of which exceed $250,000;
- $3,541,000 at Campbell Units 1 and 2 covering nine projects, none of which exceed 678,167; and
- $1,660,600 at Campbell Unit 3 covering five projects, none of which exceed 500,000.

Q. What is the basis for the projected expenses in Exhibit A-52 (NJK-3), page 1, lines 8 through 20?

A. In each year from 2027 through 2039 in the base case, the Company projects to incur major maintenance expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3,

as shown in Exhibit A-52 (NJK-3), page 1. The number of individual major maintenance projects for Karn Units 3 and 4 is as follows:

- 2027: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2028: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2029: Seven projects totaling $1,000,000, with no individual project which exceeds $250,000;
- 2030: Seven projects totaling $800,000, with no individual project which exceeds $250,000; and
- 2031: Three projects totaling $250,000, with no individual project which exceeds $150,000.

The number of individual major maintenance projects for Campbell Unit 1 is as follows:

- 2027: Seven projects totaling $2,129,667, with no individual project which exceeds $689,667;
- 2028: Six Projects totaling $2,351,167, with no individual project which exceeds $750,000;
- 2029: Six Projects totaling $1,952,667, with no individual project which exceeds $712,667;
- 2030: Four Projects totaling $1,300,000, with no individual project which exceeds $500,000; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 2 is as follows:

- 2027: Seven projects totaling $1,423,333, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,533,833, with no individual project which exceeds $500,000;

- 2029: Six Projects totaling $3,294,333, which includes;
  - Campbell 2 Turbine Valve Inspection ($1,400,000); and
  - Five Projects totaling $1,894,333 with no individual project which exceeds $500,000;
- 2030: Four Projects totaling $1,204,833, with no individual project which exceeds $404,833; and
- 2031: Two Projects totaling $300,000, with no individual project which exceeds $200,000.

The number of individual major maintenance projects for Campbell Unit 3 is as follows:

- 2027: Nine projects totaling $2,560,600, with no individual project which exceeds $500,000;
- 2028: Six Projects totaling $1,830,600, with no individual project which exceeds $500,000;
- 2029: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2030: Six Projects totaling $1,910,600, with no individual project which exceeds $500,000;
- 2031: Seven Projects totaling $1,960,600, with no individual project which exceeds $500,000;
- 2032: Seven Projects totaling $15,330,600, which includes:
  - Campbell 3 Turbine Overhaul ($12,000,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($2,000,000); and
  - Five Projects totaling $1,330,600 with no individual project which exceeds $500,000;
- 2033: Eight Projects totaling $3,860,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,300,000);

- Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
- Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;

- 2034: Five Projects totaling $1,710,600, with no individual project which exceeds $500,000;
- 2035: Eight Projects totaling $2,260,600, with no individual project which exceeds $500,000;
- 2036: Six Projects totaling $1,850,600, with no individual project which exceeds $500,000;
- 2037: Eight Projects totaling $3,960,600, which includes:
  - Campbell 3 Turbine Valve Inspection ($1,400,000);
  - Campbell 3 Base Outage Boiler and Critical Maintenance ($1,100,000); and
  - Six Projects totaling $1,460,600 with no individual project which exceeds $500,000;
- 2038: Five Projects totaling $1,360,600, with no individual project which exceeds $500,000; and
- 2039: Three Projects totaling $310,600, with no individual project which exceeds $110,600.

Q. Please explain Exhibit A-52 (NJK-3), page 2.

A. Exhibit A-52 (NJK-3), page 2, shows the Company's projected major maintenance expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 2, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 2, line 13, column (c), shows that the Company would avoid $10,050,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2023. Exhibit A-52 (NJK-3), page 2, line 13, column (f), shows

that the Company would avoid $5,700,000 in major maintenance expenses if Karn Units 3 and 4 are retired on May 31, 2025.

Q. Please explain Exhibit A-52 (NJK-3), page 3.

A. Exhibit A-52 (NJK-3), page 3, shows the Company's projected major maintenance expenses for Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-52 (NJK-3), page 3, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 3, line 21, column (c), shows that the Company would avoid $57,555,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 3, line 21, column (f), shows that the Company would avoid $29,984,000 in major maintenance expenses if Campbell Unit 3 is retired on May 31, 2032. Campbell Units 1 and 2 are not reflected in Exhibit A-52 (NJK-3), page 3, because the Campbell Unit 3 early retirement case assumes that Campbell Units 1 and 2 retire in a similar timeframe and, therefore, have identical costs to those in the base case through 2026 and 2032.

Q. Please explain Exhibit A-52 (NJK-3), page 4.

A. Exhibit A-52 (NJK-3), page 4, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 4, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 4,

line 13, columns (d) and (e), show that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 4, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 4, line 26, columns (d) and (e), shows that the Company would avoid $10,696,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 4, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and incur no incremental major maintenance expenses at Campbell Unit 2 if Campbell Unit 1 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 4, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-52 (NJK-3), page 5.

A. Exhibit A-52 (NJK-3), page 5, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52 (NJK-3), page 5,

line 13, columns (d) and (e), shows that the Company would avoid $14,625,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-52 (NJK-3), page 5, line 13, columns (i) and (j), shows that the Company would avoid $13,385,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-52 (NJK-3), page 5, line 26, columns (d) and (e), shows that the Company would avoid $12,185,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-52 (NJK-3), page 5, line 26, columns (i) and (j), show that the Company would avoid $6,427,000 in major maintenance expenses at Campbell Unit 2 and incur no incremental major maintenance expenses at Campbell Unit 1 if Campbell Unit 2 is retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 5, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses as it is assumed that unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-52 (NJK-3), page 6.

A. Exhibit A-52 (NJK-3), page 6, shows the Company's projected major maintenance expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected major maintenance expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-52 (NJK-3), page 6, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-52

(NJK-3), page 6, line 13, columns (d) and (e), shows that the Company would avoid $14,516,000 in major maintenance expenses at Campbell Unit 1 and $14,625,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2024. Exhibit A-52 (NJK-3), page 6, line 13, columns (i) and (j), shows that the Company would avoid $12,114,000 in major maintenance expenses at Campbell Unit 1 and $13,385,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2025. Exhibit A-52 (NJK-3), page 6, line 26, columns (d) and (j), shows that the Company would avoid $10,696,000 in major maintenance expenses at Campbell Unit 1 and $12,185,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2026. Exhibit A-52 (NJK-3), page 6, line 26, columns (i) and (j), shows that the Company would avoid $6,100,000 in major maintenance expenses at Campbell Unit 1 and $6,427,000 in major maintenance expenses at Campbell Unit 2 if both units are retired on May 31, 2028. Campbell Unit 3 is not reflected in Exhibit A-52 (NJK-3), page 6, because the Campbell early retirement cases do not have an impact on the Campbell Unit 3 major maintenance expenses because the unit separation major maintenance expenses reflected in the base case are not avoided.

Q. Please explain Exhibit A-53 (NJK-4), page 1.

A. Exhibit A-53 (NJK-4), page 1, shows the Company's projected base O&M expenses at the Karn and Campbell sites for each calendar year over the period from January 1, 2020 through May 31, 2039 in the base case. In this case, Karn Units 1 and 2 retire May 31, 2023, Karn Units 3 and 4 and Campbell Units 1 and 2 retire May 31, 2031, and Campbell Unit 3 retires May 31, 2039.

Q. Please explain Exhibit A-53 (NJK-4), page 2.

A. Exhibit A-53 (NJK-4), page 2, shows the Company's projected base O&M expenses for Karn Units 3 and 4 for the cases in which Karn Units 3 and 4 retire on May 31, 2023 or May 31, 2025. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2031. Exhibit A-53 (NJK-4), page 2, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 2, column (c), shows that the Company would avoid $92,202,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2023. Exhibit A-53 (NJK-4), page 2, column (f), shows that the Company would avoid $73,220,000 in base O&M expenses if Karn Units 3 and 4 retire on May 31, 2025.

Q. Please explain Exhibit A-53 (NJK-4), page 3.

A. Exhibit A-53 (NJK-4), page 3, shows the Company's projected base O&M expenses for the Campbell Unit 3 for the cases in which Campbell Unit 3 retires on May 31, 2025, or on May 31, 2032. The projected expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), page 3, also shows the difference in expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 3, column (c) shows that the Company would avoid $432,791,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2025 and Exhibit A-53 (NJK-4), page 3, column (f), shows that the Company would avoid $232,813,000 in base O&M expenses if Campbell Unit 3 retires on May 31, 2032.

Q. Please explain Exhibit A-53 (NJK-4), pages 4 and 5.

A. Exhibit A-53 (NJK-4), pages 4 and 5, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 1 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M

expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 4 and 5, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 4, line 21, columns (d), (e), and (f) shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $9,334,000 at Campbell Unit 2 and incremental base O&M expenses of $28,524,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 4, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $8,172,000 at Campbell Unit 2 and incremental base O&M expenses of $26,953,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 5, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $6,983,000 at Campbell Unit 2 and incremental base O&M expenses of $25,313,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 5, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1 and incur incremental base O&M expenses of $4,531,000 at Campbell Unit 2 and incremental base O&M expenses of $21,990,000 at Campbell Unit 3 if Campbell Unit 1 is retired on May 31, 2028.

Q. Please explain Exhibit A-53 (NJK-4), pages 6 and 7.

A. Exhibit A-53 (NJK-4), pages 6 and 7, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which Campbell Unit 2 retires on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base O&M

expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 6 and 7, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 6, line 21, columns (d), (e), and (f), shows that the Company would avoid $137,616,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,857,000 at Campbell Unit 1 and incremental base O&M expenses of $38,029,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2024. Exhibit A-53 (NJK-4), page 6, line 21, columns (j), (k), and (l) show that the Company would avoid $136,376,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,626,000 at Campbell Unit 1 and incremental base O&M expenses of $35,919,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2025. Exhibit A-53 (NJK-4), page 7, line 21, columns (d), (e), and (f) show that the Company would avoid $135,176,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,374,000 at Campbell Unit 1 and incremental base O&M expenses of $33,759,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2026. Exhibit A-53 (NJK-4), page 7, line 21, columns (j), (k), and (l), shows that the Company would avoid $129,417,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $4,785,000 at Campbell Unit 1 and incremental base O&M expenses of $29,319,000 at Campbell Unit 3 if Campbell Unit 2 is retired on May 31, 2028.

Q. Please explain Exhibit A-53 (NJK-4), pages 8 and 9.

A. Exhibit A-53 (NJK-4), pages 8 and 9, shows the Company's projected base O&M expenses for Campbell Units 1 and 2 for the cases in which both Campbell Units 1 and 2 retire on May 31, 2024, May 31, 2025, May 31, 2026, or on May 31, 2028. The projected base

O&M expenses are shown for each calendar year from January 1, 2020 through May 31, 2039. Exhibit A-53 (NJK-4), pages 8 and 9, also shows the difference in major maintenance expenses for each calendar year relative to the base case. Exhibit A-53 (NJK-4), page 8, line 21, columns (d), (e), and (f), shows that the Company would avoid $71,086,000 in base O&M expenses at Campbell Unit 1, $97,270,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $9,497,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2024. Exhibit A-53 (NJK-4), page 8, line 21, columns (j), (k), and (l), shows that the Company would avoid $61,524,000 in base O&M expenses at Campbell Unit 1, $84,186,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,989,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2025. Exhibit A-53 (NJK-4), page 9, line 21, columns (d), (e), and (f), shows that the Company would avoid $51,771,000 in base O&M expenses at Campbell Unit 1, $70,840,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $8,439,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2026. Exhibit A-53 (NJK-4), page 9, line 21, columns (j), (k), and (l), shows that the Company would avoid $31,675,000 in base O&M expenses at Campbell Unit 1, $43,343,000 in base O&M expenses at Campbell Unit 2 and incur incremental base O&M expenses of $7,331,000 at Campbell Unit 3 if Campbell Units 1 and 2 are retired on May 31, 2028.

Q. Please explain Exhibit A-54 (NJK-5).

A. Exhibit A-54 (NJK-5) shows the projected capital expenditures and costs of removal for the Company's remaining generation units. Lines 1 through 5 reflect the total for each year

of capital expenditures and costs of removal. Lines 6 through 10 reflect the total for each year of capital expenditures only.

Q. Did the Company account for the capital expenditures shown in Exhibit A-54 (NJK-5) in its IRP modeling?

A. No. The Company's IRP modeling assumed that the generation units listed in Exhibit A-54 (NJK-5) would continue operating until reaching the end of their lifespan when their book values are fully depreciated.

SECTION III: PROJECTED CAPITAL EXPENDITURES AND O&M EXPENSES OF NEW GAS PLANTS

Q. Please explain Exhibit A-55 (NJK-6) Revised.

A. Exhibit A-55 (NJK-6) Revised shows the projected capital expenditures and major maintenance expenses for the new gas plants for the period of January 1, 2020 through May 31, 2040. These are the costs and the date range that the Company used for modeling purposes in this IRP.

Q. Please explain Exhibit A-55 (NJK-6) Revised, page 1.

A. Exhibit A-55 (NJK-6) Revised, page 1, shows the Company's projected capital expenditures associated with the General Electric Long Term Service Agreement ("LTSA") for DIG and the Mitsubishi LTSA for Covert, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Covert by May 31, 2023 and the acquisition of DIG by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6) Revised, page 1, line 22, column (b), shows that the total projected LTSA capital expenditures for Covert through 2040 are $209,026,000, and Exhibit A-55 (NJK-6)

Revised, page 1, line 22, column (c), shows that the total projected LTSA capital expenditures for DIG are $~~280,091,000~~148,456,000.

Q. Please explain Exhibit A-55 (NJK-6) Revised, page 2.

A. Exhibit A-55 (NJK-6) Revised, page 2, shows the Company's projected capital expenditures for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as all projected capital expenditures for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. As discussed by Company witness Richard T. Blumenstock, the Company would complete the acquisition of Kalamazoo and Livingston by May 31, 2025, if the Company's PCA is approved. Exhibit A-55 (NJK-6) Revised, page 2, line 22, column (b), shows that the total projected non-LTSA capital expenditures for Covert through 2040 are $114,887,000, and Exhibit A-55 (NJK-6) Revised, page 2, line 22, column (c), shows that the total projected non-LTSA capital expenditures for DIG, Kalamazoo and Livingston are $~~151,696,000~~87,185,000. The projected spike in capital expenditures for non-LTSA capital expenditures in 2027 reflects work to perform rotor replacement at Covert.

Q. Please explain Exhibit A-55 (NJK-6) Revised, page 3.

A. Exhibit A-55 (NJK-6) Revised, page ~~1~~3, shows the Company's projected major maintenance expenses for the new natural gas plants associated with the General Electric and Mitsubishi LTSAs for Covert and DIG for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (b), shows that the total projected LTSA major maintenance expenses for Covert through 2040 are $69,829,000, and Exhibit A-55 (NJK-6) Revised, page 3, line 22, column (c), shows that the total projected LTSA major maintenance expenses for DIG are $50,694,000.

Q. Please explain Exhibit A-55 (NJK-6) Revised, page 4.

A. Exhibit A-55 (NJK-6) Revised, page 4, shows the Company's projected base O&M expenses for the new natural gas plants for work that is not covered by the LTSA for Covert and DIG, as well as the base O&M expenses for Kalamazoo and Livingston, for the period from January 1, 2020 through May 31, 2040. Exhibit A-55 (NJK-6) Revised, page 4, line 22, column (b), shows that the total projected non-LTSA base O&M expenses for Covert through 2040 are $511,184,000, and Exhibit A-55 (NJK-6) Revised, page 4, line 22, column (c), shows that the total projected non-LTSA base O&M expenses for DIG, Kalamazoo, and Livingston are $543,256,000. The non-LTSA base O&M expenses include both fixed and variable O&M expenses.

SECTION IV: SEPARATION ACTIVITY COSTS

Q. Please explain Exhibit A-56 (NJK-7).

A. Exhibit A-56 (NJK-7) shows the separation activity costs that the Company would incur in each retirement case. Exhibit A-56 (NJK-7), lines 1 through 9, shows the separation activity costs as they were modeled by the Company for this IRP, based on assumptions made at the time that the modeling was conducted.

Q. What are separation activity costs?

A. Separation activity costs cover those activities that are required to keep the remaining units at a site functioning when other units are retired.

Q. Are there any separation activity costs in the base case?

A. Yes. Exhibit A-56 (NJK-7), lines 1 and 2, shows that unit separation costs were modeled in the base case.

Q. What separation activity costs did the Company model in the event that Karn Units 3 and 4 were retired in 2023?

A. As shown in Exhibit A-56 (NJK-7), line 3, if Karn Units 3 and 4 are retired in 2023, the Company's IRP modeling assumes a reduction in the separation activity costs at Karn Unit 3 and 4 from $28,651,000 to $13,186,000. These costs could potentially be avoided in 2022 and 2023 once a decision to retire Karn Units 3 and 4 in 2023 is finalized.

Q. What separation activity costs did the Company model in the event that Campbell Unit 3 operated through May 31, 2039?

A. As shown in Exhibit A-56 (NJK-7), line 2, if Campbell Unit 3 operates through May 31, 2039, the Company projects that it will incur unit separation costs of $64,146,000. However, as reflected on lines 7 and 9, a Campbell Unit 3 retirement in 2025 or 2032, if coupled with a Campbell Unit 1 and 2 retirement, would allow the Company to entirely avoid the unit separation costs.

Q. What separation activity cost does the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur $64,146,000 in separation activity costs at Campbell Unit 3 in the 2024, 2025, 2026, and 2028 Campbell Unit 1 and 2 retirement cases.

Q. Is the Company requesting Commission approval of the separation activity costs for the Campbell site in this IRP proceeding?

A. No, the Company is not making such a request in *this* proceeding. The Company developed its projections of $64,146,000 in separation activity costs based on an external conceptual engineering study of the Campbell Unit 1 and 2 unit separation costs. The Company's base

case assumed that this separation work would begin in 2028 in anticipation of a May 31, 2031 retirement date for Campbell Units 1 and 2. The Company believes this estimate is accurate and, as noted above, used this figure when conducting its IRP modeling. To the extent necessary, the Company will develop a more detailed engineering study and construction plans for the separation activity. Those more specific projections for separation activity spending will be presented to the Commission and requested for approval in a future regulatory proceeding.

Q. What unit separation activity work would be required at the Campbell site?

A. The following is a high level list of activities that would be performed as part of the Campbell site unit separation:

- Mechanical isolation, cut, & caps, and new electric heating;
- Unit 1 & 2 basement sump modifications and tunnel dewatering;
- Coal pile runoff discharge treatment;
- Unit 1 & 2 communications fed from the Unit 2 switchgear building;
- Unit 2 switchgear building repower - fuel handling and Unit 1 & 2;
- Stackout and reclaim system modifications; and
- Fuel Handling Conveyor reroute/rebuild.

Q. What separation activity work does the Company plan to avoid if Karn Units 3 and 4 are retired early?

A. Under a Karn Unit 3 and 4 early retirement case, the Company would avoid capital expenditures in 2022 and 2023. It is impractical to realistically avoid any capital costs in 2021 due to the projected timing of an order in this proceeding.

Q. What is the Company's schedule for completing this work?

A. This separation work is currently underway in order to successfully retire Karn Units 1 and 2 on May 31, 2023.

Q. What are the implications of retiring Karn Units 3 and 4 in 2023 on the unit separation timeline?

A. Exhibit A-56 (NJK-7), line 3, reflects an extremely aggressive reduction in unit separation capital expenditures for this retirement case in 2022. Due to the potential timing of a final order approving the Company's PCA, it is unrealistic to avoid any unit separation capital expenditures in 2021, and the level of capital expenditures that the Company can avoid in 2022 is entirely dependent on when it receives a decision on its PCA. In order to achieve retirement of Karn Units 1 and 2 on May 31, 2023, the Company must continue to proceed with its current separation of these units from Karn Units 3 and 4.

Q. What separation activity costs did the Company model in the event that Campbell Units 1 and 2 were retired in 2024, 2025, 2028 or 2031?

A. Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, shows the costs that the Company's IRP modeling assumes would be incurred at Campbell Unit 3 if both Campbell Units 1 and 2 were retired in 2024, 2025, 2026, 2028. If only one of the two units is retired, the separation activity costs would not be incurred at Campbell Unit 3 until 2028 as modeled in the base case assuming that Campbell Unit 3 operates through 2039. However, if Campbell Unit 3 is retired in 2025 or 2032, and its retirement is coupled with a Campbell Unit 1 and 2 retirement, the unit separation costs can be avoided. The separation activity costs at Campbell Unit 3 in these bases would be an estimated $64,146,000, incurred from 2028 through 2031, to prepare Campbell Unit 3 to operate on a standalone basis once Campbell Units 1 and 2 are retired.

Q. What separation activity costs would the Company expect to actually incur in the event that Campbell Units 1 and 2 are retired early?

A. As shown in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8, the Company is still projecting that it would incur an estimated $64,146,000 in separation activity costs at Campbell Unit 3 that were projected in the IRP modeling. As previously discussed, these costs can be avoided with an early Campbell Unit 3 retirement case.

Q. If Campbell Units 1 and 2 were retired, what separation activity work would the Company plan to complete?

A. In order to allow Campbell Unit 3 to remain operating after the retirement of Campbell Units 1 and 2, the Company would leave the structure housing Campbell Units 1 and 2 in place, with its tripper deck remaining in service. All fuel handling equipment would have to be rerouted and fuel handling, the tripper deck, and ventilation and heating equipment at the site would have to be repowered from Campbell Unit 3. The fuel handling conveyor reroute work constitutes a large portion of the costs reflected in Exhibit A-56 (NJK-7), lines 4, 5, 6, and 8. Using this approach would involve fewer upfront costs and would be logistically simpler than building new fuel handling equipment. Leaving the structure housing Campbell Units 1 and 2 standing would require the Company to incur some incremental major maintenance expenses, as discussed later in my direct testimony. Because the structure would remain standing, Campbell Units 1 and 2 would not formally enter the cold and dark period, and it would likely be difficult to pursue any redevelopment opportunities at the site.

SECTION V: UNAVOIDABLE, AVOIDABLE, AND INCREMENTAL COSTS

Q. Please explain Exhibit A-57 (NJK-8) Revised.

A. Exhibit A-57 (NJK-8) Revised illustrates the Company's unavoidable, avoidable, and incremental capital expenditures for each of the early retirement cases.

Q. What are unavoidable capital expenditures?

A. Unavoidable capital expenditures represent capital expenditures that the Company must make even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

Q. Please provide an example of an unavoidable capital expenditure.

A. The Company's overall plans for capital expenditures were discussed above; the unavoidable capital expenditures are those that the Company must make in any case to ensure safety and reliability. One example of an unavoidable capital expenditure is the Campbell Unit 1 PJFF bag replacement. PJFF bags are part of the AQCS equipment which was installed to comply with Environmental Protection Agency requirements. These PJFF bags remove dry fly ash from the gas exiting the boiler and need to be replaced every four or five years to avoid failure due to plugging. Maintaining the integrity of the bags and being able to properly operate the bag cleaning system are necessary for plant operation within regulatory limits. Multiple bag failures could cause the unit to exceed opacity, resulting in unit derate or forced outage based upon the consent decree. Performance of this work will provide continued environmental compliance. This work is generally

performed on a seven-year cycle, is due to be completed in 2023, and would be required to be completed in the 2025 through 2028 Campbell Unit 1 retirement cases.

Q. What are avoidable capital expenditures?

A. Avoidable capital expenditures represent capital expenditures that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego making in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. The avoidable capital expenditures were discussed above in my discussion of Exhibit A-51 (NJK-2) Revised.

Q. What are incremental costs?

A. Incremental capital expenditures represent capital expenditures at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in the Company's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made.

Q. Please explain the incremental capital expenditures shown in Exhibit A-57 (NJK-8) Revised.

A. The incremental capital expenditures for each retirement case include the expenditures at Campbell Unit 1 in the cases in which Campbell Unit 2 is retired, and incremental capital expenditures at Campbell Unit 2 in the cases in which Campbell Unit 1 is retired. These costs are reflected in Exhibit A-57 (NJK-8) Revised, page 2, lines 4 and 8, for the 2024 retirement case. In Exhibit A-51 (NJK-2) Revised: (i) page 4, line 13, column (e), shows that if Campbell Unit 1 is retired in 2024, the Company will have $253,000 in incremental

capital expenditures at Campbell Unit 2; and (ii) page 5, line 13, column (d), shows that if Campbell Unit 2 is retired in 2024, the Company will have $322,000 in incremental capital expenditures at Campbell Unit 1. These costs represent shifting of fuel handling and infrastructure from the retired unit to the remaining unit for each of these two cases.

Q. Please explain Exhibit A-58 (NJK-9).

A. Exhibit A-58 (NJK-9) illustrates the Company's unavoidable, avoidable, and incremental major maintenance expenses for each of the early retirement cases.

Q. What are unavoidable expenses?

A. Unavoidable expenses represent major maintenance expenses that the Company must incur even in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 are retired in 2023, 2024, 2025, 2026, 2028, or 2032.

Q. Please provide an example of an unavoidable expense.

A. Consumers Energy's overall plans for expenses were discussed above; the unavoidable expenses are those that the Company must incur in any case to ensure safety and reliability. As an example, if Campbell Units 1, 2, or 3 are selected for any of the early retirement cases in in 2024, 2025, 2026, 2028, or 2032, the Company will still have O&M expenses for Mill major maintenance.

Q. What are avoidable major maintenance expenses?

A. Avoidable expenses represent major maintenance expenses that are currently scheduled to be made at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3, but that the Company would forego in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025,

2026, 2028, or 2032 are made. The avoidable expenses were discussed above in my discussion of Exhibit A-52 (NJK-3).

Q. What are incremental major maintenance expenses?

A. Incremental major maintenance expenses represent O&M expenses at Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 that are not currently included in Consumers Energy's base plans, but that the Company would need to add in the event that one or more of the various retirement cases for Karn Units 3 and 4, Campbell Units 1 and 2, and Campbell Unit 3 in 2023, 2024, 2025, 2026, 2028, or 2032 are made. As shown in Exhibit A-58 (NJK-9), pages 1 through 6, the Company has not projected any incremental major maintenance expenses for any of the retirement cases.

SECTION VI: PERFORMANCE OF EXISTING GENERATION FLEET

Q. Please explain Exhibit A-59 (NJK-10), page 1.

A. Exhibit A-59 (NJK-10), page 1, illustrates the historic and projected performance of the Company's coal-fired generating units at the Campbell and Karn sites, measuring their Random Outage Rate ("ROR").

Q. Please define ROR.

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

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

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

Conversely, increasing the frequency and/or duration of forced or unplanned generating unit outages and generating unit de-rates degrades ROR.

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

A. Initial ROR projections are based on five-year historic averages and then adjusted to reflect current operating conditions and projected unit investment. Further than five years into the future, it is increasingly difficult to accurately project ROR, as the number of unknown external factors increase. Therefore, the projected RORs for 2026 through 2031 are based on an assumed slight decrease in performance, accounting for standard corrective capital investments and maintenance.

Q. Does the ROR measurement reflect customer value?

A. While a reduced ROR may result in a benefit to customers because of the increased availability of the unit or category of unit, ROR is not itself a measure of customer benefit. The Company utilizes Net Energy Value ("NEV") to quantify this customer benefit. At a high level, NEV of a generating unit is the difference between the market value of energy and the cost of producing and supplying that energy. NEV is the net customer benefit of a generator's energy production expressed in dollars. The historical values are presented in table below.

TABLE 2

	2016	2017	2018	2019	2020	TOTAL
CAMPBELL 1	$5,963,929.	$4,201,021.	$8,497,680.	$5,687,739.	$1,468,569.	$25,818,937.
CAMPBELL 2	$6,192,416.	$2,219,726.	$9,133,940.	$4,809,091.	$948,961.	$23,304,133.
CAMPBELL 3	$19,778,737.	$28,200,856.	$47,291,421.	$30,225,507.	$19,665,066.	$145,161,587.
KARN 1	$5,989,670.	$8,176,719.	$7,238,867.	$1,954,120.	$1,362,009.	$24,721,385.
KARN 2	$5,981,023.	$4,466,650.	$6,489,054.	$438,945.	$438,017.	$17,813,688.

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

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

Q. What are the Company's expectations regarding ROR and NEV for its coal-fired generating units?

A. As presented on Exhibit A-59 (NJK-10), page 1, the Company has projected a steady decline in ROR through retirement for Campbell Units 1 and 2 and Karn Units 1 and 2. As previously discussed, the Company's projections of ROR take into account the projected unit investment and, given the current retirement dates for these units, investments targeted at improving ROR are generally uneconomic and not likely to result in providing incremental customer value. As a result, it is likely that the NEV for these units will also decline slightly as they move closer to retirement.

Q. Please explain Exhibit A-59 (NJK-10), page 2.

A. Exhibit A-59 (NJK-10), page 2, illustrates the historic Equivalent Forced Outage Rate Demand ("$EFOR_d$") of the Company's generation units at the Campbell and Karn sites.

Q. Please define $EFOR_d$.

A. $EFOR_d$ represents the hours of unit failure (Forced Outage Hours demand + Equivalent Forced Derate Hours demand), given as a percentage of the total hours of unit availability (Service Hours + Forced Outage Hours demand + Equivalent Forced Derate Hours During Reserve Shutdown).

Q. What does the ROR and $EFOR_d$ information in Exhibit A-59 (NJK-10) indicate about the condition of the existing equipment at Campbell Units 1 and 2 and Karn Units 1 and 2?

A. Exhibit A-59 (NJK-10) indicates that Campbell Units 1 and 2 have generally performed more reliably than Karn Units 1 and 2 as measured by ROR and $EFOR_d$, and the ROR of Campbell Units 1 and 2 are projected to continue demonstrating better reliability than Karn Units 1 and 2 in future years leading up to retirement. This indicates that the condition of existing equipment at Campbell Units 1 and 2 is generally better than that at Karn Units 1 and 2.

Q. Are there other measures used to inform operational and financial decisions in order to optimize the customer value of the generating unit?

A. Investments made to improve reliable operations at generating units can provide capacity value as well as energy value. The Company is required by the Midcontinent Independent System Operation, Inc. ("MISO") to secure enough capacity on an annual basis to cover all of its load, plus a reserve margin. All of the Company's units provide some capacity towards meeting this obligation and $EFOR_d$ is a measure which factors into the determination of that capacity.

Q. Please explain Confidential Exhibit A-60 (NJK-11), page 1.

A. Confidential Exhibit A-60 (NJK-11), page 1, illustrates the projected heat rates for Campbell Units 1 and 2 in the base case and the various retirement cases.

Q. Please define heat rate.

A. The heat rate or efficiency of a unit is the amount of energy used by an electrical generator to produce one kilowatt-hour (kWh) of electricity, represented in BTU/kWh.

Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 1 impacted its projected heat rates?

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 1-12, the heat rate for Campbell Unit 1 through 2023 is identical in the base case and each retirement case. However, in the 2024, 2025, and 2026 Campbell Unit 1 retirement cases, the heat rate degrades (increases) in 2024 due to the elimination of the project to replace the air preheater baskets and seals in 2023 and 2024. As such, only the base case and 2028 retirement case reflect a heat rate improvement in 2024 and beyond. No other projects in the base case provide heat rate improvement.

Q. How have the changes in projected investment in the various retirement cases for Campbell Unit 2 impacted its projected heat rates?

A. As reflected on Confidential Exhibit A-60 (NJK-11), lines 13-24, the heat rate for Campbell Unit 2 through 2031 is identical in the base case and each retirement case. The reason for this is that there are no major Campbell Unit 2 projects with heat rate effects after the Turbine/Generator work and air heater seal replacement work in 2021. As such, the heat rate degradation is the same for all cases.

SECTION VII: EXECUTION RISKS OF EARLY RETIREMENT

Q. What execution risks does the Company face in its plan to retire the Campbell site in 2025?

A. Since the Company is recommending that the Campbell site be retired early, there are several factors that could make the actual operation of those units until May 31, 2025 difficult. These factors include issues related to plant maintenance and employee retention.

Q. What are the risks related to plant maintenance?

A. The Company will continue to make capital investments and incur O&M expenses at Campbell site in order to ensure safe operation. However, as the units get closer to their early retirement date, the Company will have to evaluate any unexpected maintenance issues that may arise to determine if the economics of the situation would justify performing repairs. For example, if one of the units experiences a turbine failure one year prior to the retirement date, the Company would consider both the costs and benefits of replacement and/or repair before proceeding. If replacement and/or repair would result in high costs that could not be recovered before retirement, and replacement energy could be purchased through the MISO market, and replacement capacity could be purchased bilaterally, at a more economic price than the price of replacement and/or repair, then the Company could elect to leave the affected unit in an outage until the retirement date.

Q. What are the risks related to employee retention?

A. The Company will develop a thorough plan to ensure that the necessary qualified employees are retained to operate the units through the retirement date, as well as during the cold and dark time period following retirement, as discussed later in my direct testimony. However, once it is certain that the units will retire, employees may begin to

seek positions elsewhere in the Company, or externally. In that circumstance, it could become difficult for the units to be safely operated through the retirement date. When the Company retired the Classic 7 in 2016, and made plans to retire Karn Units 1 and 2 in 2023, the Company was able to mitigate these employee retention risks because it had time to develop a transition plan that gave employees needed confidence to remain at those units through the closure date, knowing that they would likely be able to move to other positions within the Company afterward. However, with the retirement of all remaining coal units, the difficulty of this task has significantly increased. Further, the Company has observed situations involving other utilities in which the retirement of a generation plant was made more difficult by less than adequate human resource management and planning. For example, there have been situations at other utilities in which plant employees were not provided any kind of post-closure transition plan, meaning those employees were liable to lose their jobs, resulting in low morale and delays in the retirement of the plant. By having an effective transition plan in place for employees, the Company can effectively mitigate these risks.

Q. Is the Company considering environmental risks in retiring the Campbell site?

A. Yes. When the units are retired, the Company will have to bring the units into compliance with environmental regulations. This will include vacuuming all ash, draining boilers, and removing all oil from the machinery. The Company will ensure that nothing is left at the site that may leak and release pollution into the environment. In performing this environmental work, the Company will ensure that it does not, and will not, exceed any regulatory limits on emissions into local waterways throughout the prolonged cold and dark period, which will require sufficient time during the cold and dark period. If the Company

does not have sufficient time to do this cleaning, it runs the risk of significantly increased clean-up costs in order to ensure that the Company does not violate emissions limits and completes all necessary clean-up work. In addition to the clean-up work itself, the Company will also need to address the coal pile. The Company plans to burn the coal pile down in the final weeks of the units' operation, so that as little coal remains onsite as possible. The Company will evaluate remediation of the land on which the coal pile sits to determine if that land can be redeveloped for other purposes.

Q. Is the Company considering risks related to the future use of the site?

A. Yes. The Company has recent experience in evaluating future use of a retired generation unit site, having done so when the Classic 7 were retired and currently doing so for the Karn site. During the Classic 7 retirement process, the Company evaluated various future use options for those sites, and Consumers Energy had enough time in that process to effectively study the divestment of those sites and opportunities to divest to third parties who would also manage facility demolition and redevelopment, mitigating the risk of unnecessarily high costs and optimizing customer value since a specialized firm would manage demolition and redevelopment instead of the Company doing so directly. In the case of Campbell site, the Company would also need time to study different future use options for the site, and to vet different options for both Company-managed demolition and redevelopment and for divestment to a third-party firm to do that work.

Q. Are there future use risks related to the local community?

A. Impacts to the community when the Campbell site retires are discussed later in my direct testimony. At a high level, the retirement will impact the community's tax base and employment base. The Company is committed to assisting in redevelopment of the site to

offset these impacts, and to communicating with the community as much as possible to facilitate this.

Q. If Campbell Units 1 and 2 were retired in 2024 instead of 2025, as the Company considered in other cases, would there be additional risks?

A. Yes. As noted above, the Company has demonstrated an ability to responsibly and safely retire and decommission a coal-fired generation unit when given sufficient time to develop a transition plan that ensures needed employee retention so that operations can be appropriately wound down in a safe and environmentally responsible manner, which would also allow the Company to assess impacts to the local community and develop a transition plan for that as well. Assuming that this filing receives Commission approval in 2022, a 2024 retirement date does not give the Company adequate time. A 2024 retirement date would not allow the Company enough time to implement a safe and responsible transition plan for environmental clean-up, for employee transitions, or for community transitions.

Q. Are there any further concerns related to retiring Campbell Units 1 and 2 in 2024 instead of 2025?

A. Yes. The Company has made significant capital investments in Campbell Units 1 and 2 to ensure their compliance with environmental standards as well as to maintain reliability. Operating Campbell Units 1 and 2 until 2025 increases the benefits of those investments as the units will continue to provide energy and capacity for a longer period of time; conversely, retiring Campbell Units 1 and 2 in 2024 would reduce the time that those capital investments provide benefits to customers.

Q. Are there any risks that would result in Campbell site being required to be operated beyond 2025?

A. Yes. To retire a generation unit, the Company must get approval from MISO. MISO will study the Company's retirement proposal to ensure that it does not create transmission reliability concerns, particularly related to maintaining voltage on the transmission system. If MISO finds that transmission reliability concerns will exist, MISO may require one or more of the units to remain in operation until such time that a solution is found and completed to mitigate the reliability problem. As part of its stakeholder process, MISO would consider solutions, such as: (i) re-dispatch or reconfiguration of the transmission system; (ii) special protection schemes; (iii) contracted demand response; (iv) new or expanded generation elsewhere on the system; and (v) transmission expansion.

Q. What would happen if MISO does require one or both units to remain in operation?

A. If MISO makes such a determination, it would designate the unit or units as a System Support Resource ("SSR"). When a unit becomes an SSR, MISO ensures that the unit fully recovers its ongoing operating costs by assigning those costs to affected MISO transmission customers through MISO's Federal Energy Regulatory Commission-regulated transmission rates.

SECTION VIII: TAX, COMMUNITY, AND EMPLOYEE IMPACTS OF EARLY RETIREMENT

Karn Units 3 and 4

Q. What is the tax impact of Karn Units 3 and 4?

A. The Company pays property taxes on Karn Units 3 and 4 that fund local governmental services provided by Hampton Township and Bay County. The units' 2020 taxable value was $25.6 million, which was approximately 0.87% of the total taxable value in Bay

County and 7.6% of the total taxable value in Hampton Township. The units' 2021 taxable value had a small increase of approximately 1%.

Q. Aside from property tax revenues, what other impacts will the retirement of Karn Units 3 and 4 in 2023 have on its respective community?

A. Gas-fired generation units provide employment in the communities in which they are located and can be local economic drivers. Retirement of Karn Units 3 and 4 in combination with Karn Units 1 and 2 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

Q. How will the Company provide that help?

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company has commissioned a detailed future-use study to analyze specific potential opportunities to redevelop the Karn site.

Q. Please explain the community transition plan for Karn Units 3 and 4.

A. The community transition plan for Karn Units 3 and 4 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. This transition will be updated by the Company subsequent to this filing. The transition plan will identify and describe the economic strengths of Bay County and advantages of the Karn site for future redevelopment, which would be explored

in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area and potential threats to redevelopment.

Q. Please describe the results of the Company's transition planning for retirement of the Classic 7.

A. The Company's transition plans for the Classic 7 focused on a smooth transition through open communication and regional sustainable vision alignment. The performance of future use studies along with collaboration with community stakeholders were critical to the Classic 7 decommissioning process. The Company's community partners included residents, government officials, state elected officials, economic development organizations, vendors, state agencies, and employees affected by the closure.

Q. How has the Company's community engagement resulted in success for the affected communities?

A. The Company's community engagement process at its Cobb plant, which is located at the Port of Muskegon, helped regional community leaders find new solutions to market and manage the port and re-imagine the potential for Muskegon Lake. Current plans include conversion of the area into a deep-water marine terminal. Similarly, the Company's stakeholder engagement process associated with the closing, near-complete demolition and active redevelopment of the Whiting plant will result in a site which is ideal for manufacturing and warehousing based upon its extensive logistical advantages such as rail and direct access to I-75.

Q. Please explain the community communication plan for Karn Units 3 and 4.

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Karn Units 3 and 4; this communication is the key first

step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

Q. Please explain the future-use study process for Karn Units 3 and 4.

A. The Company has been conducting a future-use study as part of its process for planning to retire Karn Units 1 and 2. These studies will consider environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. The retirement of all four Karn units in 2023 will un-restrain potential redevelopment options for the Karn site which is adjacent to the formerly retired Weadock site. Previous redevelopment options for the Weadock site were limited to reuse by the Company for other purposes. The Company will consider options for private redevelopment, as the retirement of Karn Units 1, 2, 3, & 4 may make more of the site, such as the port facilities, available for redevelopment.

Q. How will the retirement of Karn Units 3 and 4 in 2023 affect Company employees?

A. The employees that support the operation of Karn Units 1 and 2 as well as Karn Units 3 and 4 are Karn site employees. As such, all of the employees that directly support day-to-day facility operation were included in the Company's retention and separation program which was established to support the retirement of Karn Units 1 and 2 in 2023. The

Company continues to be committed to ensuring a smooth transition for the Karn employees as the decommissioning process for the Karn site is implemented.

Campbell Units 1, 2, and 3

Q. What is the tax impact of Campbell Units 1, 2, and 3?

A. The Company pays property taxes on Campbell Units 1, 2, and 3 that fund local governmental services provided by Port Sheldon Township and Ottawa County. The units' 2020 taxable valuation was $143.8 million, which is approximately 1.15% of the total taxable value in Ottawa County and 27% of the total taxable value in Port Sheldon Township. The units' 2021 taxable value declined by 12.5%, due to a decline in market conditions for coal-fired power plants. The overall taxable value of the Campbell site is expected to continue to decline due to negative market conditions facing coal-fired generation.

Q. Aside from property tax revenues, what other impacts will the retirement of Campbell Units 1, 2, and 3 in 2025 have on its respective community?

A. Coal-fired generation units provide employment in the communities in which they are located and can be significant local economic drivers. Retirement of Campbell Units 1, 2, and 3 in 2025 will bring economic transition to the affected community. The Company is committed to helping the local community transition to a new economic landscape after retirement.

Q. How will the Company provide that help?

A. The Company will develop a community transition plan that analyzes the economic strengths and weaknesses of the community that will affect the transition after the units are retired, as well as potential threats to the transition. This community transition plan will

be closely coordinated with a communications strategy that will ensure that all relevant stakeholders are properly informed about the plan. Additionally, the Company plans to complete a detailed future-use study to analyze specific potential opportunities to redevelop the Campbell site.

Q. Please explain the community transition plan.

A. The community transition plan for Campbell Units 1, 2, and 3 will be similar in intent to community transition plans that the Company developed for the retirement of the Karn Units 1 and 2 and the Classic 7. The transition plan will identify and describe the economic strengths of Ottawa County and advantages of the Campbell site for future redevelopment, which would be explored in more detail in a future-use study. The transition plan also identifies economic weaknesses in the area, and potential threats to redevelopment.

Q. Please explain the community communication plan.

A. The Company began implementation of the communication plan as soon as the Company announced that it planned to retire Campbell Units 1, 2, and 3; this communication is the key first step in implementing the community transition plan, beginning the process of engaging stakeholders. Immediately prior to this filing, the Company notified all affected stakeholders of the retirement proposal, with the stakeholders including employees, local governments, community business leaders, local media, and local community organizations. Stakeholders also include State of Michigan government agencies and state and federal elected officials. The Company will be in communication throughout the retirement process with community stakeholders. All identified stakeholders will receive relevant communication at regular intervals from assigned Company representatives.

Q. Please explain the future-use study process.

A. The Company previously developed future-use studies as part of its process for retiring the Classic 7 and, as previously mentioned, is in the process of conducting a future use study for the Karn site. These studies considered environmental issues and local economic issues, such as real estate markets and demographics, and analyzed potential redevelopment options for each site. Because the Company intends to retire the Campbell site in its entirety, the potential redevelopment options are less restrained than if only one or two of the three units were retired.

Q. How many employees does the Company currently have at the Campbell site?

A. The Campbell site currently has 405 employees at the Campbell site, 313 of whom directly support day-to-day facility operation, with representatives of the Company's Generation Operations, Generation Engineering, Environmental, and other groups. Within the total number of 313 employees that directly support day-to-day facility operation, 214 employees are operations, maintenance, and construction ("OM&C") employees, 75 are exempt employees, and 24 are non-exempt employees. Employees in executive, manager and supervisor, professional, and outside sales positions are considered by the Company to be *exempt* from the Fair Labor Standards Act's minimum wage, overtime pay, and certain record-keeping requirements, and are considered at-will employees. Employees who work as technicians, office and clerical staff, and administrative support are considered *not to be exempt* from those requirements. OM&C employees at the Campbell site are represented by the Utility Workers Union of America ("UWUA").

Q. How will the retirement of the Campbell site in 2025 affect Company employees?

A. The Company is committed to ensuring a smooth transition for employees as the decommissioning process for Campbell is implemented. The Company will use regular and transparent internal communications with its employees to ensure that employees are informed about the Company's plans. The Company will leverage the lessons it learned from its successful experience in retiring the Classic 7 and planning for retirement of Karn Units 1 and 2 in developing a retention and separation plan to govern how employees are treated during the decommissioning process of Campbell Units.

Q. What is the Company's intended timing for its retention and separation plan?

A. Once a retirement date for the Campbell site is established, pursuant to an MPSC order in this case, the Company will implement a retention plan that takes effect 40 months prior to that retirement date. For example, if the Campbell Units are scheduled to complete their cold and dark activities by October 31, 2025, then the retention plan would go into effect on July 1, 2022. The retention plan for OM&C employees was previously negotiated with the UWUA and approved by Company leadership; retention plans for other classifications of employees have been developed by the Company, as well. The separation plan exists within current Company agreements and policies and would take effect when the Campbell site retires.

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

A. The Company has a strong interest in keeping qualified employees working at the Campbell site through the site's retirement date to ensure safe and reliable operations. Once a retirement date for the Campbell site is confirmed, some employees may seek employment at other Company locations or outside of the Company; meanwhile, hiring

new employees at the Campbell site will become more difficult given the short remaining lifespan of the units, plus the training time necessary for any new hires is challenging. Using the best practices that the Company employed in retiring the Classic 7 and planning for the retirement of Karn Units 1 and 2, the Company plans to offer retention bonuses to all impacted employees who stay at the Campbell site for the entire 40-month period noted above.

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

A. When the Campbell site is retired, the Company plans to follow the terms of the collective bargaining agreement for OM&C employees represented by the UWUA and the terms of the employee handbook policy and separation plan for non-represented exempt and non-exempt employees. The structure and amount of the severance offers will vary based on employee salary and classification due to differences in the terms of the separation plan covering non-represented employees and the bargaining agreement for UWUA-represented employees. In the event that exempt or non-exempt employees cannot find placement with the Company within 30 miles from their current location, they will be offered involuntary severance in accordance with the terms of the Company's Salaried Separation Plan. The Company's Working Agreement with the UWUA governs separation for OM&C employees who elect to leave the Company rather than accept a new position; relocation policies for OM&C employees are explained in further detail below.

Q. What are the estimated costs of the retention and separation plan?

A. Based on current employment levels and demographics, the Company estimates the costs of this retention program, including estimated severance and moving cost, is $60 million if all employees qualify for the retention bonus and all retirement-eligible employees accept

a severance offer. It is the Company's intent to find placements for as many employees as possible, thus mitigating the cost of separations.

Q. Is the Company requesting recovery of the retention incentive costs in this proceeding?

A. Yes. As discussed by Company Witness Jason R. Coker, the Company is requesting the expense recognition to be deferred as a regulatory asset until such time that the expenses are recovered in rates.

Q. What is the possible impact to affected employees at the Campbell site?

A. The Company expects that approximately 313 employees will be needed to continue operation of the Campbell site until its proposed retirement in 2025. The rest of the employees will be covered by the policy relevant to their classification. The Working Agreement covering OM&C employees guarantees all eligible OM&C employees a position at their current respective wage within 60 miles of the Campbell site. It is the Company's intent that all exempt and non-exempt employees, who desire to retain employment with the Company, will be offered another position. However, in the event that exempt or non-exempt employees cannot find placement within the Company, they will be offered involuntary severance in accordance with the terms of the Salaried Separation Plan. The Company has 7 locations within 60 miles of the Campbell site.

Q. What is the Company's recent history with managing employee impacts following the retirement of a coal-fired power plant?

A. Following the retirement of the Classic 7 in 2016, all Company employees who desired to continue employment with the Company were able to do so. The Company believes that this demonstrates the Company's commitment to its employees. The retirement of the

Classic 7 was successful because all employees had confidence that they would maintain secure employment following plant closure. As described earlier in my direct testimony, maintaining this confidence is essential for mitigating the Company's execution risk in retiring the Campbell site.

Q. How much time is needed for the Company to execute its plan for employees?

A. As discussed above, the Company plans for its retention plan to cover a 40-month period, preceded by negotiation and approval. This period of time is particularly necessary because many employees will need to be retrained for new jobs. When the Company retired the Classic 7, many operators were able to move to other coal-fired facilities within the Company, limiting the need for retraining. Since the Company plans to retire all of its remaining coal-fired units, this option is no longer available. Furthermore, the 7 Company locations within 60 miles of the Campbell site consist of numerous service centers, where the work is substantially different than at a generating site. Employees from the Campbell site who move, for example, to the West Kent Service Center may need several months of training to become certified in the distribution maintenance work done at that location. The Company's goal is to facilitate a smooth transition by having employees trained to move into new positions as soon as possible after the retirement of the Campbell site. The Company is capable of managing this transition, having done so with the Classic 7, but it needs sufficient time for workforce planning as well to ensure that appropriate positions are available for employees.

Q. To minimize retraining, could the Company relocate employees from the Campbell site to the Covert site?

A. Yes. The Covert site is within 60 miles of the Campbell site. While gas and coal generating plants are operated differently, there are many similarities with respect to maintenance which could allow for a relatively smooth transition for some Campbell employees. To the extent that employees relocate to locations which are not within a 60 mile radius of the Campbell site, the Company's Working Agreement covering OM&C employees allows those employees to receive Company-paid moving expenses if they accept a position more than 60 miles away, and the Company is providing an additional relocation incentive for employees moving more than 60 miles.

Q. Does this conclude your direct testimony?

A. Yes.

Attachment FF

NPDES Permit - FINAL_CECO -
J H Campbell Power Plant

PERMIT NO. MI0001422

STATE OF MICHIGAN
DEPARTMENT OF ENVIRONMENT, GREAT LAKES, AND ENERGY

AUTHORIZATION TO DISCHARGE UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM

In compliance with the provisions of the Federal Water Pollution Control Act, 33 U.S.C., Section 1251 *et seq*., as amended; Part 31, Water Resources Protection, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended (NREPA); Part 41, Sewerage Systems, of the NREPA; and Michigan Executive Order 2019-06,

Consumers Energy Company
One Energy Plaza
Jackson, MI 49201

is authorized to discharge from the **Consumers Energy Company, J. H. Campbell Power Plant** located at

17000 Croswell St.
West Olive, MI 49460

designated as **CECO-J H Campbell Power Plt**

to the receiving waters named Lake Michigan and the Pigeon River in accordance with effluent limitations, monitoring requirements, and other conditions set forth in this permit.

This permit is based on a complete application submitted on March 22, 2016, as amended through September 1, 2016; and a complete modification request submitted on January 11, 2021.

This permit originally took effect on June 1, 2018. This modified permit takes effect on October 1, 2021. The provisions of this permit are severable. After notice and opportunity for a hearing, this permit may be modified, suspended, or revoked in whole or in part during its term in accordance with applicable laws and rules. On its original effective date, the permit superseded National Pollutant Discharge Elimination System (NPDES) Permit No. MI0001422 (expiring October 1, 2016).

This permit and the authorization to discharge shall expire at midnight on **October 1, 2022**. In order to receive authorization to discharge beyond the date of expiration, the permittee shall submit an application that contains such information, forms, and fees as are required by the Michigan Department of Environment, Great Lakes, and Energy (Department) by **April 4, 2022**.

Issued: May 29, 2018. Modified (major) September 30, 2021.

Original signed by Christine Alexander
Christine Alexander, Manager
Permits Section
Water Resources Division

PERMIT FEE REQUIREMENTS

In accordance with Section 324.3120 of the NREPA, the permittee shall make payment of an annual permit fee to the Department for each October 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by January 15 for notices mailed by December 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after December 1.

Annual Permit Fee Classification: Industrial-Commercial Major

In accordance with Section 324.3118 of the NREPA, the permittee shall make payment of an annual storm water fee to the Department for each January 1 the permit is in effect regardless of occurrence of discharge. The permittee shall submit the fee in response to the Department's annual notice. Payment may be made electronically via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Payment shall be submitted or postmarked by March 15 for notices mailed by February 1. Payment shall be submitted or postmarked no later than 45 days after receiving the notice for notices mailed after February 1.

CONTACT INFORMATION

Unless specified otherwise, all contact with the Department required by this permit shall be made to the Grand Rapids District Office of the Water Resources Division. The Grand Rapids District Office is located at State Office Building, Fifth Floor, 350 Ottawa Ave NW, Unit 10, Grand Rapids, Michigan, 49503-2341, Telephone: 616-356-0500, Fax: 616-356-0202.

CONTESTED CASE INFORMATION

Any person who is aggrieved by this permit may file a sworn petition with the Michigan Administrative Hearing System within the Michigan Department of Licensing and Regulatory Affairs, c/o the Michigan Department of Environment, Great Lakes, and Energy, setting forth the conditions of the permit which are being challenged and specifying the grounds for the challenge. The Department of Licensing and Regulatory Affairs may reject any petition filed more than 60 days after issuance as being untimely.

PART I

Section A. Limitations and Monitoring Requirements

1. Effluent Limitations, Monitoring Point 001A

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 984.841 MGD of noncontact cooling water; intake screen backwash; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, and water from floor drains; bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; storm water; leachate retention pond water; reverse osmosis backwash and reject water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 001A through Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	(report)	(report)	MGD	---	---	---	Daily	Report Total Daily Flow
Total Residual Oxidant (TRO) – See Part I.A.1.g.								
During Chlorination – No Bromine Use								
Total Residual Chlorine (TRC) Discharge Time			---	---	(report)	min/day	Daily	Report Total Discharge Time
Continuous (greater than 160 min/day)	---	---	---	---	38	ug/l	Daily	Grab
				Daily Average	**Instantaneous Maximum**			
Intermittent (less than/equal to 160 min/day)				200	300	ug/l	Daily	Grab
During Bromination – Alone or With Chlorine								
Intermittent (less than/equal to 120 min/day)				(report)	50	ug/l	Daily	Grab
					Maximum Daily			
TRO Discharge Time		---	---	---	120	min/day	Daily	Report Total Discharge Time
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Copper, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.1.i.	---	---	---	---	(report)	mg/l	Daily	Grab
EVAC (as amine)	---	---	---	---	78	ug/l	Every 2 Hrs During Discharge	Grab
Temperature								
Intake (Unit 3 intake)	---	---	---	(report)	(report)	°F	Daily	Continuous
Discharge	---	---	---	(report)	(report)	°F	Daily	Continuous
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual

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Section A. Limitations and Monitoring Requirements

Parameter	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring Frequency	Sample Type
	Monthly	Daily	Units	Monthly	Daily	Units		
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Lake Michigan. Intake temperature monitoring shall be taken at the Unit 3 intake.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Analytical Methods and Quantification Levels for Total Phosphorus and Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Phosphorus and Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Phosphorus and Total Copper, shall be 10 ug/l and 1.0 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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Section A. Limitations and Monitoring Requirements

g. Total Residual Oxidant (Chlorine and Bromine) Requirements

Total Residual Oxidant (TRO) shall be analyzed in accordance with Part II.B.2. of this permit. TRO monitoring is only required during periods of chlorine or bromine use and subsequent discharge. The limitations specified in Part I.A.1. for the intermittent discharge of chlorine alone apply only when the discharge of chlorine alone is less than or equal to 160 minutes per day, otherwise the limitations for continuous discharge of chlorine alone apply. Authorization to discharge bromine alone or with chlorine is limited to 120 minutes per day at the limitations specified in Part I.A.1., with the additional requirement that any discharge of chlorine is further restricted to a concurrent discharge with bromine (no additional discharge of chlorine is authorized for that day).

During the intermittent discharge of chlorine without bromine ("During Chlorination – No Bromine Use"), the daily average concentration reported for TRC shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a chlorine discharge event, with the additional limitation that no single sample may exceed 300 ug/l.

During the intermittent discharge of bromine alone or with chlorine ("During Bromination – Alone or With Chlorine"), the daily average concentration reported for TRO shall be the average of the individual analytical results of a minimum of three (3) grab samples collected at equal intervals during a bromine, or bromine plus chlorine, discharge event, with the limitation that no single sample may exceed 50 ug/l of TRO.

The permittee shall enter "*G" on the Discharge Monitoring Report for the TRO discharge modes not being used.

The permittee may use dehalogenation techniques to achieve the applicable TRO limitations, using sodium thiosulfate, sodium sulfite, sodium bisulfite, or other dehalogenating reagents approved by the Department. The quantity of the reagent(s) used shall be limited to 0.6 times the stoichiometric amount of TRO for sodium thiosulfate, 1.5 times the stoichiometric amount of TRO for sodium bisulfite, and 1.8 times the stoichiometric amount of TRO for sodium sulfite. The TRO samples taken to determine the amount of each chemical to add shall be taken upstream of dehalogenation.

h. Zebra Mussel Control Requirements

The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than 12 hours per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge.

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report “<” the quantification level used by the analyzing laboratory on the DMR.

i. Total Copper and Total Iron Monitoring

The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 001A.

j. Temperature Monitoring

When the continuous temperature monitoring system is inoperative, the effluent daily maximum temperature may be reported on a single daily reading.

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Section A. Limitations and Monitoring Requirements

k. Acid Cleaning
The periodic use of Muriatic acid for cleaning sodium hypochlorite injection systems nozzles is approved.

l. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

2. Effluent Limitations, Monitoring Point 001B (Ash Pond System Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 7.77 MGD of bottom ash transport water; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater, which includes but is not limited to: boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject, and water from floor drains; storm water; leachate retention pond water; and groundwater seepage from ash ponds and recirculation pond from Monitoring Point 001B through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.2.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Annual Monitoring
Annual samples shall be taken during the month of April. If the facility does not discharge during this month, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

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Section A. Limitations and Monitoring Requirements

d. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

3. Effluent Limitations, Monitoring Point 001C (Plant Oil/Water Separator Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 9.65 MGD of noncontact cooling water; low volume wastewater, which includes but is not limited to: boiler blowdown, recirculating house service water, laboratory and sampling streams, and water from floor drains; treated coal pile runoff; and storm water from Monitoring Point 001C through Monitoring Point 001A and Outfall 001. Outfall 001 discharges to Lake Michigan at Latitude 42.91164, Longitude -86.21269. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration				
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Monitoring Frequency**	**Sample Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	25	40	mg/l	Monthly	Grab
Oil & Grease	---	---	---	---	10	mg/l	Monthly	Grab

a. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to Units 1 & 2 intake channel.

b. Monitoring Frequency Reduction for Oil & Grease
After the submittal of 12 months of data, the permittee may request, in writing, Department approval for a reduction in monitoring frequency for Oil & Grease. This request shall contain an explanation as to why the reduced monitoring is appropriate. Upon receipt of written approval and consistent with such approval, the permittee may reduce the monitoring frequency indicated in Part I.A.3. of this permit. The monitoring frequency for Oil & Grease shall not be reduced to less than Annually. The Department may revoke the approval for reduced monitoring at any time upon notification to the permittee.

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Section A. Limitations and Monitoring Requirements

4. Effluent Limitations, Monitoring Point 002A (Ash Pond Discharge)

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 10.45 MGD of bottom ash transport water; economizer ash wastewater; chemical metal cleaning wastewater; coal pile runoff; low volume wastewater which includes but is not limited to: ion exchange wastewater, boiler blowdown, boiler drainage, recirculating house service water, laboratory and sampling streams, reverse osmosis backwash and reject water, and water from floor drains; storm water; and groundwater seepage from ash ponds and the recirculation pond from Monitoring Point 002A through Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	(report)	(report)	MGD	---	---	---	2X Monthly	Report Total Daily Flow
Total Suspended Solids	---	---	---	30	50	mg/l	Monthly	Grab
Oil & Grease	---	---	---	15	20	mg/l	Annually	Grab
Total Copper, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Iron, see Part I.A.4.f.	---	---	---	---	(report)	mg/l	Daily	Grab
Total Arsenic	---	(report)	lbs/day	---	(report)	ug/l	Quarterly	Grab
Total Phosphorus (as P)	---	(report)	lbs/day	---	(report)	mg/l	Quarterly	Grab
Total Selenium	0.47	(report)	lbs/day	5.3	(report)	ug/l	Quarterly	Grab
EVAC (as amine), see Part I.A.4.h.		---	---	---	78	ug/l	See Permit Requirements	Grab
Outfall Observation	(report)	---	---	---	---	---	5X Weekly	Visual
				Minimum Daily				
pH	---	---	---	6.5	9.0	S.U.	2X Monthly	Grab

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to discharge to the Pigeon River.

c. Outfall Observation
Outfall observation shall be reported as "yes" or "no." The permittee shall report yes if this requirement was completed and no if this requirement was not completed. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended

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Section A. Limitations and Monitoring Requirements

solids, or deposits) shall be reported within 24 hours to the Department followed with a written report within 5 days detailing the findings of the investigation and the steps taken to correct the condition.

d. Quarterly and Annual Monitoring
Quarterly samples shall be taken during the months of January, April, July, and October. Annual samples shall be taken during the month of April. If the facility does not discharge during these months, the permittee shall sample the next discharge occurring during the period in question. If the facility does not discharge during the period in question, a sample is not required for that period. For any month in which a sample is not taken, the permittee shall enter "*G" on the Discharge Monitoring Report (DMR).

e. Water Treatment Additives
This permit does not authorize the discharge of water treatment additives without approval. Approval of water treatment additives is authorized under separate correspondence. Water treatment additives include any material that is added to water used at the facility or to a wastewater generated by the facility to condition or treat the water. In the event a permittee proposes to discharge water treatment additives, including an increased discharge concentration of a previously approved water treatment additive, the permittee shall submit a request for approval in accordance with Part I.A.6. of this permit.

f. Total Copper and Total Iron Monitoring
The monitoring requirements for total copper and total iron apply only when a discharge from the chemical treatment facility occurs through Monitoring Point 002A.

g. Analytical Methods and Quantification Levels for Total Arsenic, Total Copper, and Total Phosphorus
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Arsenic, Total Copper, and Total Phosphorus shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Arsenic, Total Copper, and Total Phosphorus shall be 1.0 ug/l, 1.0 ug/l, and 10 ug/l, respectively, unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

h. Zebra Mussel Control Requirements
The discharge of EVAC (as amine) is restricted to no more than six (6) times per year, for no more than five (5) days per discharge event. The permittee shall notify the Department at least one (1) week prior to each discharge. Upon initiation of each EVAC treatment, samples shall be collected at Monitoring Point 002A at least once every three hours for a twelve (12) hour period. Once treatment is complete following the twelve (12) hour period, sampling will occur once daily the following day for five consecutive days to show that the concentration (as an amine) measured at Monitoring Point 002A is below detection (zero).

The sampling procedure, preservation and handling, and analytical protocol for compliance monitoring for EVAC (as amine) shall be in accordance with the Acid Orange Method. The quantification level shall not exceed 50 ug/l for EVAC (as amine), unless higher levels are appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Other methods may be used upon approval from the Department. The highest value measured during the discharge event shall be reported. If the concentration in all samples is less than the quantification level, report “<” the quantification level used by the analyzing laboratory on the DMR.

i. Power Plants – Polychlorinated Biphenyls (PCB) Prohibition
The permittee shall not discharge any PCBs to the receiving waters of the state of Michigan as a result of plant operations.

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Section A. Limitations and Monitoring Requirements

5. Effluent Limitations, Monitoring Point 002C

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge a maximum of 1.092 MGD of chemical metal cleaning wastewater from Monitoring Point 002C through Monitoring Point 002A and Outfall 002. Outfall 002 discharges to the Pigeon River at Latitude 42.90292, Longitude -86.196033. Such discharge shall be limited and monitored by the permittee as specified below.

	Maximum Limits for Quantity or Loading			Maximum Limits for Quality or Concentration			Monitoring	Sample
Parameter	**Monthly**	**Daily**	**Units**	**Monthly**	**Daily**	**Units**	**Frequency**	**Type**
Flow	---	(report)	MGD	---	---	---	Monthly	Report Total Daily Flow
Total Copper, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab
Total Iron, see Part I.A.5.a.	---	---	---	---	1.0	mg/l	Daily	Grab

a. Total Copper and Total Iron Limits
The limits and monitoring requirements for total copper and total iron apply only to the discharge from the chemical treatment facility when operating. The chemical treatment facility effluent shall not be mixed with any other waste stream prior to sampling for compliance monitoring. All samples shall be taken prior to discharge to the recirculation pond.

b. Monitoring Location
Samples, measurements, and observations taken in compliance with the monitoring requirements above shall be taken prior to the Unit 2 condenser discharge channel.

c. Analytical Methods and Quantification Levels for Total Copper
The sampling procedures, preservation and handling, and analytical protocol for compliance monitoring for Total Copper shall be in accordance with Part II.B.2. of this permit. The quantification level for Total Copper shall be 1.0 ug/l unless a higher level is appropriate because of sample matrix interference. Justification for higher quantification levels shall be submitted to the Department within 30 days of such determination. Upon approval from the Department, the permittee may use alternate analytical methods (for parameters with methods specified in Title 40 of the Code of Federal Regulations (CFR), Part 136, the alternate methods are restricted to those listed in 40 CFR, Part 136).

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Section A. Limitations and Monitoring Requirements

6. Request for Discharge of Water Treatment Additives

Prior to discharge of any water treatment additive, the permittee shall obtain written approval from the Department. Requests for such approval shall be submitted via the Department's MiWaters system. The MiWaters website is located at https://miwaters.deq.state.mi.us. Instructions for submitting such a request may be obtained at http://www.michigan.gov/deqnpdes (near the bottom of that page, click on one or both of the links located under the Water Treatment Additives banner). Additional monitoring and reporting may be required as a condition for the approval to discharge the additive.

A request to discharge water treatment additives shall include all of the following usage and discharge information for each water treatment additive proposed to be discharged:

a. Safety Data Sheet (formerly known as Material Safety Data Sheet);

b. the proposed water treatment additive discharge concentration with supporting calculations;

c. the discharge frequency (i.e., number of hours per day and number of days per year);

d. the outfall and monitoring point from which the product is to be discharged;

e. the type of removal treatment, if any, that the water treatment additive receives prior to discharge;

f. the product's function (i.e. microbiocide, flocculant, etc.);

g. a 48-hour LC_{50} or EC_{50} for a North American freshwater planktonic crustacean (either *Ceriodaphnia sp., Daphnia sp., or Simocephalus sp.*); and

h. the results of a toxicity test for one (1) other North American freshwater aquatic species (other than a planktonic crustacean) that meets a minimum requirement of R 323.1057(2) of the Water Quality Standards. Examples of tests that would meet this requirement include a 96-hour LC_{50} for rainbow trout, bluegill, or fathead minnow.

7. Cold Shock Prevention

Cessation of thermal inputs to the receiving water by this facility shall occur gradually so as to avoid fish mortality due to cold shock during the winter months (November through March). The basis for this requirement is to allow fish associated with the discharge-heated mixing zone for Outfall 001 to acclimate to the decreasing temperature. The Department acknowledges that the permittee meets this condition based on the equipment and practices implemented at Outfall 001 identified in the application.

8. Intake Screen Backwash, Outfall 001

During the period beginning on the effective date of this permit and lasting until the expiration date of this permit, the permittee is authorized to discharge intake screen backwash from Outfall 001 to Lake Michigan. The permittee shall collect and remove debris accumulated on intake trash bars and dispose of such material on land in an appropriate manner.

9. Periodic/Temporary Rerouting of Combined Plant Discharge

The permittee is authorized to divert the combined flow from Units 1 & 2 and Unit 3 offshore intake structure under the following conditions: (a) for deicing when the intake water temperature falls below 36^{o} F and intakes are at risk of becoming partially or completely restricted because of icing, (b) when Unit 3 is off line during a scheduled or unscheduled outage and the deepwater discharge pumps are turned off, or (c) for thermal treatment or control of zebra mussels and asiatic clams. The permittee is not required to provide any additional monitoring of this discharge because the effluent limitations and monitoring requirements for Outfall 001, for

PART I

Section A. Limitations and Monitoring Requirements

which monitoring/reporting shall be continued as usual during the diversion, will determine compliance with the applicable water quality standards and any other requirements.

10. Cooling Water Intake Structures – Interim Approval

The federal rules promulgated by the United States Environmental Protection Agency (USEPA) in 40 CFR Parts 122 and 125 establishing the requirements of section 316(b) of the Clean Water Act for Existing Facilities took effect October 14, 2014. Beginning October 14, 2014, any facility covered by the rules requesting permit reissuance shall submit an application in accordance with the rules and shall be subject to the best technology available (BTA) standards for impingement mortality and entrainment as defined in the rules. In accordance with 40 CFR 125.95(a)(2), the Department approved the permittee's March 10, 2016, request for an alternate schedule for submission of the information required in 40 CFR 122.21(r). The alternate schedule for submission of the reports identified in the request for is set for April 30, 2018 (received).

The cooling water intake structure operated by the permittee has been evaluated using all available information relating to its location, design, construction, and capacity. At this time, the Department has made an **interim** determination that the cooling water intake structure represents BTA to minimize adverse environmental impact in accordance with section 316(b) of the federal Clean Water Act (33 U.S.C. section 1326). The permittee shall at all times properly operate and maintain the cooling water intake structure and associated equipment to minimize adverse environmental impact. The permittee shall give advance notice to the Department of any planned changes in the location, design, operation, or capacity of the intake structure. If the Department determines that additional technologies or control measures are necessary to reduce the impact of impingement or entrainment, the Department may revise the requirements of this condition. Nothing in this permit shall either be construed to relieve the permittee from civil or criminal penalties for previous or future fish losses, or authorize take for the purposes of a facility's compliance with the Endangered Species Act.

11. Facility Contact

The "Facility Contact" was specified in the application. The permittee may replace the facility contact at any time, and shall notify the Department in writing within 10 days after replacement (including the name, address and telephone number of the new facility contact).

a. The facility contact shall be (or a duly authorized representative of this person):
   - for a corporation, a principal executive officer of at least the level of vice president; or a designated representative if the representative is responsible for the overall operation of the facility from which the discharge originates, as described in the permit application or other NPDES form,
   - for a partnership, a general partner,
   - for a sole proprietorship, the proprietor, or
   - for a municipal, state, or other public facility, either a principal executive officer, the mayor, village president, city or village manager or other duly authorized employee.

b. A person is a duly authorized representative only if:
   - the authorization is made in writing to the Department by a person described in paragraph a. of this section; and
   - the authorization specifies either an individual or a position having responsibility for the overall operation of the regulated facility or activity such as the position of plant manager, operator of a well or a well field, superintendent, position of equivalent responsibility, or an individual or position having overall responsibility for environmental matters for the facility (a duly authorized representative may thus be either a named individual or any individual occupying a named position).

Nothing in this section obviates the permittee from properly submitting reports and forms as required by law.

PART I

Section A. Limitations and Monitoring Requirements

12. Discharge Monitoring Report – Quality Assurance Study Program

The permittee shall participate in the Discharge Monitoring Report – Quality Assurance (DMR-QA) Study Program. The purpose of the DMR-QA Study Program is to annually evaluate the proficiency of all in-house and/or contract laboratory(ies) that perform, on behalf of the facility authorized to discharge under this permit, the analytical testing required under this permit. In accordance with Section 308 of the Clean Water Act (33 U.S.C. § 1318); and R 323.2138 and R 323.2154 of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, participation in the DMR-QA Study Program is required for all major facilities, and for minor facilities selected for participation by the Department.

Annually and in accordance with DMR-QA Study Program requirements and submittal due dates, the permittee shall submit to the Michigan DMR-QA Study Program state coordinator all documentation required by the DMR-QA Study. DMR-QA Study Program participation is required only for the analytes required under this permit and only when those analytes are also identified in the DMR-QA Study.

If the permitted facility's status as a major facility should change, participation in the DMR-QA Study Program may be reevaluated. Questions concerning participation in the DMR-QA Study Program should be directed to the Michigan DMR-QA Study Program state coordinator.

All forms and instructions required for participation in the DMR-QA Study Program, including submittal due dates and state coordinator contact information, can be found at http://www.epa.gov/compliance/discharge-monitoring-report-quality-assurance-study-program.

13. Schedule of Compliance for Bottom Ash Transport Water

The permittee shall manage the discharge of bottom ash transport water (BATW) to surface waters of the state in accordance with EPA's Final Steam Electric Reconsideration Rule (Final Rule), effective October 13, 2020. This schedule of compliance (SOC) is based on two separate compliance pathways established by the Final Rule for BATW: the Cessation of Coal Burning Activities subcategory, and the implementation of an ELG-compliant technology. The permittee shall attain compliance with the Final Rule by completing the following requirements.

a. On or before October 13, 2021, the permittee shall:

1) submit a Notice of Planned Participation (NOPP) in the Cessation of Coal Burning Activities subcategory in accordance with 40 CFR §423.19 – if this compliance pathway is being considered, and/or

2) submit an update on the feasibility evaluation to select an ELG-compliant technology – if this compliance pathway is being considered.

b On or before April 4, 2022, with the application for reissuance, the permittee shall submit a description of the ELG-compliant technology selected – if the ELG-compliant technology pathway is being considered.

PART I

Section A. Limitations and Monitoring Requirements

c. On or before December 31, 2022, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway is being considered, and/or

2) commence the engineering and design process for implementation of the selected ELG-compliant technology and submit a status report on this process – if this compliance pathway is being considered.

d. On or before December 31, 2023, the permittee shall submit to the Department a report identifying the final pathway selected for compliance with the Final Rule: either the Cessation of Coal Burning Activities subcategory (including the annual progress report in accordance with 40 CFR §423.19), or the implementation of an ELG-compliant technology.

e. On or before December 31, 2024, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or

2) continue construction of the selected ELG-compliant technology and submit a construction status report that includes a description of any impediments to final implementation by December 31, 2025 – if this compliance pathway was selected.

f. On or before December 31, 2025, the permittee shall:

1) submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory – if this compliance pathway was selected, or

2) submit an Initial Certification Statement in accordance with 40 CFR §423.19(c) and comply with the requirements set forth in Part I.A.14.b. of this permit – if the ELG-compliant technology pathway was selected.

g. If the permittee selected the Cessation of Coal Burning Activities subcategory as the final pathway for compliance with the Final Rule, the permittee shall complete the following:

1) On or before December 31, 2026, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.

2) On or before December 31, 2027, the permittee shall submit an annual progress report in accordance with 40 CFR §423.19 to ensure compliance under the Cessation of Coal Burning Activities subcategory.

3) On or before December 31, 2028, the permittee shall comply with the requirements set forth in Part I.A.14.a. of this permit.

PART I

Section A. Limitations and Monitoring Requirements

14. Bottom Ash Transport Water Discharge Prohibition

a. If the permittee has certified to the Department the intention to pursue the Cessation of Coal Burning Activities subcategory as set forth in Part I.A.13. of this permit, then the discharge of all BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit until no later than December 31, 2028, by which date the permittee shall cease discharge of newly generated BATW from any outfall and the discharge of previously generated BATW shall comply with the final effluent limitations set forth in Part I.A.2. and Part I.A.4. of this permit.

b. Beginning December 31, 2025, the permittee is prohibited from discharging newly generated BATW from any outfall in accordance with 40 CFR 423.13(k)(1), except for those discharges to which paragraph (k)(2) applies. After December 31, 2025, any discharge volume of BATW shall be reduced or eliminated to the extent achievable using control measures that are technologically available and economically achievable in light of best industry practices. The total volume of BATW allowed to be discharged under (k)(2) shall be determined by the Department on a case-by-case basis and in no event shall such discharge exceed a 30-day rolling average of 10 percent of the primary active wetted bottom ash system volume. At least 180 days prior to the discharge of any newly generated BATW, the permittee shall submit to the Department all information required under 40 CFR 423.19(c) for reviews required under (k)(2).

The Department may modify or reissue this permit in accordance with applicable rules in order to establish the permit requirements set forth in the rules for 40 CFR Part 423, Steam Electric Power Generating Point Source Category.

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Section B. Storm Water Pollution Prevention

1. Final Effluent Limitations and Monitoring Requirements

The permittee is authorized to discharge storm water associated with industrial activity, as defined under 40 CFR 122.26(b)(14)(i-ix), to the surface waters of the state. Such discharge shall be limited and monitored by the permittee as specified below.

a. Narrative Standard
The receiving water shall contain no turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits as a result of this discharge in unnatural quantities which are or may become injurious to any designated use.

b. Visual Assessment of Storm Water Discharges
To ensure that storm water discharges from the facility do not violate the narrative standard in the receiving waters, storm water discharges shall be visually assessed in accordance with this permit.

c. Implementation of Storm Water Pollution Prevention Plan
The permittee shall implement an acceptable Storm Water Pollution Prevention Plan (SWPPP) as required by this permit.

d. Certified Operator
The permittee shall have an Industrial Storm Water Certified Operator who has supervision over the facility's storm water treatment and control measures included in the SWPPP.

PART I

Section B. Storm Water Pollution Prevention

The Storm Water Pollution Prevention Plan (SWPPP) is a written procedure to reduce the exposure of storm water to significant materials and to reduce the amount of significant materials in the storm water discharge. An acceptable SWPPP shall identify potential sources of contamination and describe the controls necessary to reduce their impacts in accordance with Part I.B.2. through Part I.B.8. of this permit.

2. Source Identification

To identify potential sources of significant materials that can pollute storm water and subsequently be discharged from the facility, the SWPPP shall, at a minimum, include the following:

a. A site map identifying:

1) buildings and other permanent structures;

2) storage or disposal areas for significant materials;

3) secondary containment structures and descriptions of the significant materials contained within the primary containment structures;

4) storm water discharge points (which include outfalls and points of discharge), numbered or otherwise labeled for reference;

5) location of storm water and non-storm water inlets (numbered or otherwise labeled for reference) contributing to each discharge point;

6) location of NPDES-permitted discharges other than storm water;

7) outlines of the drainage areas contributing to each discharge point;

8) structural controls or storm water treatment facilities;

9) areas of vegetation (with brief descriptions such as lawn, old field, marsh, wooded, etc.);

10) areas of exposed and/or erodible soils and gravel lots;

11) impervious surfaces (e.g., roofs, asphalt, concrete, etc.);

12) name and location of receiving water(s); and

13) areas of known or suspected impacts on surface waters as designated under Part 201 (Environmental Response) of the NREPA.

b. A list of all significant materials that could pollute storm water. For each material listed, the SWPPP shall include each of the following descriptions:

1) the ways in which each type of significant material has been, or has reasonable potential to become, exposed to storm water (e.g., spillage during handling; leaks from pipes, pumps, and vessels; contact with storage piles, contaminated materials, or soils; waste handling and disposal; deposits from dust or overspray; etc.);

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2) identification of the discharge point(s) and the inlet(s) contributing the significant material to each discharge point through which the significant material may be discharged if released; and

3) an evaluation of the reasonable potential for contribution of significant materials to storm water from at least the following areas or activities:

a) loading, unloading, and other significant material-handling operations;

b) outdoor storage, including secondary containment structures;

c) outdoor manufacturing or processing activities;

d) significant dust- or particulate-generating processes;

e) discharge from vents, stacks, and air emission controls;

f) on-site waste disposal practices;

g) maintenance and cleaning of vehicles, machines, and equipment;

h) areas of exposed and/or erodible soils;

i) Sites of Environmental Contamination listed under Part 201 (Environmental Response) of the NREPA;

j) areas of significant material residues;

k) areas where animals (wild or domestic) congregate and deposit wastes; and

l) other areas where storm water may come into contact with significant materials.

c. A listing of significant spills and significant leaks of polluting materials that occurred in areas that are exposed to precipitation or that discharge to a point source at the facility. The listing shall include spills that occurred over the three (3) years prior to the effective date of a permit authorizing discharge. The listing shall include the date, volume, and exact location of the release, and the action taken to clean up the material and/or prevent exposure to storm water or contamination of surface waters of the state. Any release that occurs after the SWPPP has been developed shall be controlled in accordance with the SWPPP and is cause for the SWPPP to be updated as appropriate within 14 calendar days of obtaining knowledge of the spill or loss.

d. A determination as to whether its facility discharges storm water to a water body for which an EPA-approved Total Maximum Daily Load (TMDL) has been established. If so, the permittee shall assess whether the TMDL requirements for the facility's discharge are being met through the existing SWPPP controls or whether additional control measures are necessary. The permitee's assessment of whether the TMDL requirements are being met shall focus on the effectiveness, adequacy, and implementation of the permitee's SWPPP controls.

e. A summary of existing storm water discharge sampling data (if available), describing pollutants in storm water discharges at the facility. This summary shall be accompanied by a description of the suspected source(s) of the pollutants detected.

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Section B. Storm Water Pollution Prevention

3. Nonstructural Controls

To prevent significant materials from contacting storm water at the source, the SWPPP shall, at a minimum, include each of the following nonstructural controls:

a. Written procedures and a schedule for routine preventive maintenance. Preventive maintenance procedures shall describe routine inspections and maintenance of storm water management and control devices (e.g., cleaning of oil/water separators and catch basins, routine housekeeping activities, etc.), as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to the storm sewer system or the surface waters of the state. The routine inspection shall include areas of the facility in which significant materials have the reasonable potential to contaminate storm water. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

b. Written procedures and a schedule for good housekeeping to maintain a clean, orderly facility. Good housekeeping procedures shall include routine inspections that focus on the areas of the facility that have a reasonable potential to contaminate storm water entering the property. The routine housekeeping inspections may be combined with the routine inspections for the preventive maintenance program. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below.

c. Written procedures and a schedule for **quarterly** comprehensive site inspections, to be conducted by the Industrial Storm Water Certified Operator. At a minimum, one inspection shall be performed within each of the following quarters: January-March, April-June, July-September, and October-December. The comprehensive site inspections shall include, but not be limited to, inspection of structural controls in use at the facility, and the areas and equipment identified in the routine preventive maintenance and good housekeeping procedures. These inspections shall also include a review of the routine preventive maintenance reports, good housekeeping inspection reports, and any other paperwork associated with the SWPPP. The permittee may request Department approval of an alternate schedule for comprehensive site inspections. A written report of the inspection and corrective actions shall be retained in accordance with Record Keeping, below, and the following shall be included on the comprehensive inspection form/report:

    1) Date of the inspection.

    2) Name(s), title(s), and certification number(s) of the personnel conducting the inspection.

    3) Precipitation information (i.e., a description of recent rainfall/snowmelt events).

    4) All observations relating to the implementation of control measures. Items to include if applicable:

        a) updates on corrective actions implemented due to previously identified pollutant and/or discharge issues;

        b) any evidence of, or the potential for, pollutants to discharge to the drainage system or receiving waters and the condition of and around the discharge point including flow dissipation measures needing maintenance or repairs;

        c) any control measures needing maintenance or repairs; and

        d) any additional control measures needed to comply with permit requirements.

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5) Any required revisions to the SWPPP resulting from the inspection.

6) A written certification stating the facility is in compliance with this permit and the SWPPP, or, if there are instances of noncompliance, they are identified.

7) Written procedures and a schedule for **quarterly** visual assessments of storm water discharges. At a minimum, one visual assessment shall be conducted within each of the following quarters: January-March, April-June, July-September, and October-December. These assessments shall be conducted as part of the comprehensive site inspection within one month of control measure observations made in accordance with 4), above. If the Department has approved an alternate schedule for the comprehensive site inspection, the visual assessment may likewise be conducted in accordance with the same approved alternate schedule.

The following are the requirements of the visual assessment. The permittee shall develop and clearly document, in writing, procedures for meeting these requirements:

a) Within six (6) months of the effective date of this permit, the permittee shall develop written procedures for conducting the visual assessment and incorporate these procedures into the SWPPP. If Qualified Personnel rather than an Industrial Storm Water Certified Operator will collect storm water samples, these procedures shall include a written description of the training given to these personnel to qualify them to collect the samples, as well as documentation verifying that these personnel have received this training. The first visual assessment shall be conducted in conjunction with the next occurring comprehensive inspection. If changes resulting in altered drainage patterns occur at the facility, the permittee shall modify the procedures for conducting the visual assessment in accordance with the requirements of Keeping SWPPPs Current, below, and these modifications shall be incorporated into the SWPPP prior to conducting the next visual assessment.

b) A visual assessment shall be conducted of a representative storm water **sample** collected **from each storm water discharge point**. Storm water samples shall be visually assessed for conditions that could cause a violation of water quality standards as defined in Water Quality Standards, below. The visual assessment shall be made of the storm water sample in a clean, clear glass or plastic container. Only an Industrial Storm Water Certified Operator shall conduct this visual assessment. Visual assessment of the storm water sample shall be conducted within 48 hours of sample collection.

Representative storm water samples shall be collected:

(1) from each storm water discharge point identified as set forth under Source Identification, above. These samples may be collected by one or more of the following: an Industrial Storm Water Certified Operator; and/or an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the sample (“Qualified Personnel”); and/or an automated sampling device; and

(2) within the first 30 minutes of the start of a discharge from a storm event and on discharges that occur at least 72 hours (3 days) from the previous discharge. If it is not possible to collect the sample within the first 30 minutes of discharge, the sample shall be collected as soon thereafter as practicable, but not exceeding 60 minutes. In the case of snowmelt, samples shall be collected during a period with measurable discharge from the site.

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c) A visual assessment shall be conducted of the storm water **discharge at each storm water discharge point**. (If an automated sampling device is used to collect the storm water sample, this requirement is waived). Either an Industrial Storm Water Certified Operator and/or Qualified Personnel may conduct this visual assessment. This visual assessment may be conducted directly – by someone physically present at the storm water discharge at each storm water discharge point; or it may be conducted indirectly – through the use of a visual recording taken of the storm water discharge at each storm water discharge point. Direct visual assessment shall be conducted at the same time that the storm water sample is collected. Indirect visual assessment shall be conducted using a visual recording taken of the storm water discharge at the same time that the storm water sample was collected.

d) Visual assessments shall be documented. This documentation shall be retained in accordance with Record Keeping, below, and shall include the following:

(1) sampling location(s) at the storm water discharge point(s) identified on the site map (see Source Identification, above);

(2) storm event information (i.e., length of event expressed in hours, approximate size of event expressed in inches of precipitation, duration of time since previous event that caused a discharge, and date and time the discharge began);

(3) date and time of the visual assessment of each storm water **discharge** at each storm water discharge point;

(4) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who conducted the visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(5) observations made during visual assessment of the storm water **discharge** at each storm water discharge point. If an automated sampling device was used to collect the storm water sample associated with this discharge point, this documentation requirement is waived;

(6) if applicable, any visual recordings used to conduct the visual assessment of the storm water **discharge** at each storm water discharge point;

(7) date and time of sample collection for each storm water **sample**;

(8) name(s) and title(s) of the Industrial Storm Water Certified Operator or Qualified Personnel who collected the storm water **sample**. If an automated sampling device was used to collect the storm water sample, the permittee shall document that, instead;

(9) date and time of the visual assessment of each storm water **sample**;

(10) name(s), title(s), and operator number(s) of the Industrial Storm Water Certified Operator(s) who conducted the visual assessment of each storm water **sample**;

(11) observations made during visual assessment of each storm water **sample**;

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(12) full-color photographic evidence of the storm water **sample** against a white background;

(13) nature of the discharge (i.e., rainfall or snowmelt);

(14) probable sources of any observed storm water contamination; and

(15) if applicable, an explanation for why it was not possible to collect samples within the first 30 minutes of discharge.

e) When adverse weather conditions prevent a visual assessment during the quarter, a substitute visual assessment shall be conducted during the next qualifying storm event. Documentation of the rationale for no visual assessment during a quarter shall be included with the SWPPP records as described in Record Keeping, below. Adverse conditions are those that are dangerous or create inaccessibility for personnel, such as local flooding, high winds, electrical storms, or situations that otherwise make sampling impractical such as drought or extended frozen conditions.

f) If the facility has two (2) or more discharge points that are believed to discharge substantially identical storm water effluents, the facility may conduct visual assessments of the discharge at just one (1) of the discharge points and report that the results also apply to the other substantially identical discharge point(s). The determination of substantially identical discharge points is to be based on the significant material evaluation conducted as set forth under Source Identification, above, and shall be clearly documented in the SWPPP. Visual assessments shall be conducted on a rotating basis of each substantially identical discharge point throughout the period of coverage under this permit.

d. A description of material handling procedures and storage requirements for significant materials. Equipment and procedures for cleaning up spills shall be identified in the SWPPP and made available to the appropriate personnel. The procedures shall identify measures to prevent spilled materials or material residues from contaminating storm water entering the property. The SWPPP shall include language describing what a reportable spill or release is and the appropriate reporting requirements in accordance with Part II.C.6. and Part II.C.7. The SWPPP may include, by reference, requirements of either a Pollution Incident Prevention Plan (PIPP) prepared in accordance with the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); a Hazardous Waste Contingency Plan prepared in accordance with 40 CFR 264 and 265 Subpart D, as required by Part 111 of the NREPA; or a Spill Prevention Control and Countermeasure (SPCC) plan prepared in accordance with 40 CFR 112.

e. Identification of areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion. Gravel lots shall be included. The SWPPP shall also identify measures used to control soil erosion and sedimentation.

f. A description of the employee training program that will be implemented on an annual basis to inform appropriate personnel at all levels of their responsibility as it relates to the components and goals of the SWPPP. The SWPPP shall identify periodic dates for the employee training program. Records of the employee training program shall be retained in accordance with Record Keeping, below.

g. Identification of actions to limit the discharge of significant materials in order to comply with TMDL requirements, if applicable.

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h. Identification of significant materials expected to be present in storm water discharges following implementation of nonstructural preventive measures and source controls.

4. Structural Controls

Where implementation of the measures required by Nonstructural Controls, above, does not control storm water discharges in accordance with Water Quality Standards, below, the SWPPP shall provide a description of the location, function, design criteria, and installation/construction schedule of structural controls for prevention and treatment. Structural controls may be necessary:

a. to prevent uncontaminated storm water from contacting, or being contacted by, significant materials; or

b. if preventive measures are not feasible or are inadequate to keep significant materials at the site from contaminating storm water. Structural controls shall be used to treat, divert, isolate, recycle, reuse, or otherwise manage storm water in a manner that reduces the level of significant materials in the storm water and provides compliance with water quality standards as identified in Water Quality Standards, below.

5. Keeping SWPPPs Current

a. The permittee and/or the Industrial Storm Water Certified Operator shall review the SWPPP annually after it is developed and maintain a written report of the review in accordance with Record Keeping, below. Based on the review, the permittee or the Industrial Storm Water Certified Operator shall amend the SWPPP as needed to ensure continued compliance with the terms and conditions of this permit. The written report shall be submitted to the Department on or before January 10th of each year.

b. The SWPPP developed under the conditions of a previous permit shall be amended as necessary to ensure compliance with this permit.

c. The SWPPP shall be updated or amended whenever changes at the facility have the potential to increase the exposure of significant materials to storm water, significant spills occur at the facility, or when the SWPPP is determined by the permittee or the Department to be ineffective in achieving the general objectives of controlling pollutants in storm water discharges associated with industrial activity. Updates based on increased activity or spills at the facility shall include a description of how the permittee intends to control any new sources of significant materials, or respond to and prevent spills in accordance with the requirements of this permit (see Source Identification; Nonstructural Controls; and Structural Controls, above).

d. The Department may notify the permittee at any time that the SWPPP does not meet minimum requirements of this permit. Such notification shall identify why the SWPPP does not meet minimum requirements of this permit. The permittee shall make the required changes to the SWPPP within 30 days after such notification from the Department or authorized representative and shall submit to the Department a written certification that the requested changes have been made.

e. Amendments to the SWPPP shall be signed and retained on-site with the SWPPP pursuant to Signature and SWPPP Review, below.

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Section B. Storm Water Pollution Prevention

6. Industrial Storm Water Certified Operator Update

If the Industrial Storm Water Certified Operator is changed or an Industrial Storm Water Certified Operator is added, the permittee shall provide the name and certification number of the new Industrial Storm Water Certified Operator to the Department. If a facility has multiple Industrial Storm Water Certified Operators, the names and certification numbers of all shall be included in the SWPPP.

7. Signature and SWPPP Review

a. The SWPPP shall be reviewed and signed by the Industrial Storm Water Certified Operator(s) and by either the permittee or an authorized representative in accordance with 40 CFR 122.22. The SWPPP and associated records shall be retained on-site at the facility that generates the storm water discharge.

b. The permittee shall make the SWPPP, reports, log books, storm water discharge sampling data (if collected), and items required by Record Keeping, below, available upon request to the Department. The Department makes the non-confidential business portions of the SWPPP available to the public.

8. Record Keeping

The permittee shall maintain records of all SWPPP-related inspection and maintenance activities. Records shall also be kept describing incidents such as spills or other discharges that can affect the quality of storm water. All such records shall be retained for three (3) years. The following records are required by this permit (see Nonstructural Controls; and Keeping SWPPPs Current, above):

a. routine preventive maintenance inspection reports;

b. routine good housekeeping inspection reports;

c. comprehensive site inspection reports;

d. documentation of visual assessments;

e. employee training records; and

f. written summaries of the annual SWPPP review.

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Section B. Storm Water Pollution Prevention

9. Water Quality Standards

At the time of discharge, there shall be no violation of water quality standards in the receiving waters as a result of the storm water discharge. This requirement includes, but is not limited to, the following conditions:

a. In accordance with R 323.1050 of the Part 4 Rules promulgated pursuant to Part 31 of the NREPA, the receiving waters shall not have any of the following unnatural physical properties as a result of this discharge in quantities which are, or may become, injurious to any designated use: turbidity, color, oil films, floating solids, foams, settleable solids, suspended solids, or deposits.

b. Any unusual characteristics of the discharge (i.e., unnatural turbidity, color, oil film, floating solids, foams, settleable solids, suspended solids, or deposits) shall be reported within 24 hours to the Department, followed by a written report within five (5) days detailing the findings of the investigation and the steps taken to correct the condition.

c. Any pollutant for which a level of control is specified to meet a TMDL established by the Department shall be controlled at the facility so that its discharge is reduced by/to the amount specified in the TMDL.

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Section B. Storm Water Pollution Prevention

10. Prohibition of Non-Storm Water Discharges

Discharges of material other than storm water shall be in compliance with an NPDES permit issued for the discharge. Storm water shall be defined to include all of the following non-storm water discharges, provided pollution prevention controls for the non-storm water component are identified in the SWPPP:

a. discharges from fire hydrant flushing;

b. potable water sources, including water line flushing;

c. water from fire system testing and fire-fighting training without burned materials or chemical fire suppressants;

d. irrigation drainage;

e. lawn watering;

f. routine building wash-down that does not use detergents or other compounds;

g. pavement wash waters where contamination by toxic or hazardous materials has not occurred (unless all contamination by toxic or hazardous materials has been removed) and where detergents are not used;

h. uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;

i. springs;

j. uncontaminated groundwater;

k. foundation or footing drains where flows are not contaminated with process materials such as solvents; and

l. discharges from fire-fighting activities. Discharges from fire-fighting activities are exempted from the requirement to be identified in the SWPPP.

11. Tracer Dye Discharges

This permit does not authorize the discharge of tracer dyes without approval from the Department. Requests to discharge tracer dyes shall be submitted to the Department in accordance with Rule 1097 (R 323.1097 of the Michigan Administrative Code).

PART II

Part II may include terms and /or conditions not applicable to discharges covered under this permit.

Section A. Definitions

Acute toxic unit (TU_A) means $100/LC_{50}$ where the LC_{50} is determined from a whole effluent toxicity (WET) test which produces a result that is statistically or graphically estimated to be lethal to 50% of the test organisms.

Annual monitoring frequency refers to a calendar year beginning on January 1 and ending on December 31. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Authorized public agency means a state, local, or county agency that is designated pursuant to the provisions of section 9110 of Part 91 of the NREPA to implement soil erosion and sedimentation control requirements with regard to construction activities undertaken by that agency.

Best management practices (BMPs) means structural devices or nonstructural practices that are designed to prevent pollutants from entering into storm water, to direct the flow of storm water, or to treat polluted storm water.

Bioaccumulative chemical of concern (BCC) means a chemical which, upon entering the surface waters, by itself or as its toxic transformation product, accumulates in aquatic organisms by a human health bioaccumulation factor of more than 1000 after considering metabolism and other physiochemical properties that might enhance or inhibit bioaccumulation. The human health bioaccumulation factor shall be derived according to R 323.1057(5). Chemicals with half-lives of less than 8 weeks in the water column, sediment, and biota are not BCCs. The minimum bioaccumulation concentration factor (BAF) information needed to define an organic chemical as a BCC is either a field-measured BAF or a BAF derived using the biota-sediment accumulation factor (BSAF) methodology. The minimum BAF information needed to define an inorganic chemical as a BCC, including an organometal, is either a field-measured BAF or a laboratory-measured bioconcentration factor (BCF). The BCCs to which these rules apply are identified in Table 5 of R 323.1057 of the Water Quality Standards.

Biosolids are the solid, semisolid, or liquid residues generated during the treatment of sanitary sewage or domestic sewage in a treatment works. This includes, but is not limited to, scum or solids removed in primary, secondary, or advanced wastewater treatment processes and a derivative of the removed scum or solids.

Bulk biosolids means biosolids that are not sold or given away in a bag or other container for application to a lawn or home garden.

Certificate of Coverage (COC) is a document, issued by the Department, which authorizes a discharge under a general permit.

Chronic toxic unit (TU_C) means 100/MATC or $100/IC_{25}$, where the maximum acceptable toxicant concentration (MATC) and IC_{25} are expressed as a percent effluent in the test medium.

Class B biosolids refers to material that has met the Class B pathogen reduction requirements or equivalent treatment by a Process to Significantly Reduce Pathogens (PSRP) in accordance with the Part 24 Rules. Processes include aerobic digestion, composting, anaerobic digestion, lime stabilization and air drying.

Combined sewer system is a sewer system in which storm water runoff is combined with sanitary wastes.

PART II

Section A. Definitions

Daily concentration is the sum of the concentrations of the individual samples of a parameter divided by the number of samples taken during any calendar day. If the parameter concentration in any sample is less than the quantification limit, regard that value as zero when calculating the daily concentration. The daily concentration will be used to determine compliance with any maximum and minimum daily concentration limitations (except for pH and dissolved oxygen). When required by the permit, report the maximum calculated daily concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the Discharge Monitoring Reports (DMRs).

For pH, report the maximum value of any *individual* sample taken during the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs and the minimum value of any *individual* sample taken during the month in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. For dissolved oxygen, report the minimum concentration of any *individual* sample in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Daily loading is the total discharge by weight of a parameter discharged during any calendar day. This value is calculated by multiplying the daily concentration by the total daily flow and by the appropriate conversion factor. The daily loading will be used to determine compliance with any maximum daily loading limitations. When required by the permit, report the maximum calculated daily loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMRs.

Daily monitoring frequency refers to a 24-hour day. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Department means the Michigan Department of Environment, Great Lakes, and Energy.

Detection level means the lowest concentration or amount of the target analyte that can be determined to be different from zero by a single measurement at a stated level of probability.

Discharge means the addition of any waste, waste effluent, wastewater, pollutant, or any combination thereof to any surface water of the state.

EC_{50} means a statistically or graphically estimated concentration that is expected to cause 1 or more specified effects in 50% of a group of organisms under specified conditions.

Fecal coliform bacteria monthly
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a discharge event. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR. If the period in which the discharge event occurred was partially in each of two months, the calculated monthly value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria monthly is the geometric mean of all daily concentrations determined during a reporting month. Days on which no daily concentration is determined shall not be used to determine the calculated monthly value. The calculated monthly value will be used to determine compliance with the maximum monthly fecal coliform bacteria limitations. When required by the permit, report the calculated monthly value in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

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Section A. Definitions

Fecal coliform bacteria 7-day
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days of discharge during a discharge event. If the number of daily concentrations determined during the discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean value for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. If the 7-day period was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – Fecal coliform bacteria 7-day is the geometric mean of the daily concentrations determined during any 7 consecutive days in a reporting month. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. Days on which no daily concentration is determined shall not be used to determine the value. The calculated 7-day value will be used to determine compliance with the maximum 7-day fecal coliform bacteria limitations. When required by the permit, report the maximum calculated 7-day geometric mean for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs. The first calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

Flow-proportioned sample is a composite sample with the sample volume proportional to the effluent flow.

General permit means a National Pollutant Discharge Elimination System permit issued authorizing a category of similar discharges.

Geometric mean is the average of the logarithmic values of a base 10 data set, converted back to a base 10 number.

Grab sample is a single sample taken at neither a set time nor flow.

IC_{25} means the toxicant concentration that would cause a 25% reduction in a nonquantal biological measurement for the test population.

Illicit connection means a physical connection to a municipal separate storm sewer system that primarily conveys non-storm water discharges other than uncontaminated groundwater into the storm sewer; or a physical connection not authorized or permitted by the local authority, where a local authority requires authorization or a permit for physical connections.

Illicit discharge means any discharge to, or seepage into, a municipal separate storm sewer system that is not composed entirely of storm water or uncontaminated groundwater. Illicit discharges include non-storm water discharges through pipes or other physical connections; dumping of motor vehicle fluids, household hazardous wastes, domestic animal wastes, or litter; collection and intentional dumping of grass clippings or leaf litter; or unauthorized discharges of sewage, industrial waste, restaurant wastes, or any other non-storm water waste directly into a separate storm sewer.

Individual permit means a site-specific NPDES permit.

Inlet means a catch basin, roof drain, conduit, drain tile, retention pond riser pipe, sump pump, or other point where storm water or wastewater enters into a closed conveyance system prior to discharge off site or into waters of the state.

PART II

Section A. Definitions

Interference is a discharge which, alone or in conjunction with a discharge or discharges from other sources, both: 1) inhibits or disrupts the POTW, its treatment processes or operations, or its sludge processes, use or disposal; and 2) therefore, is a cause of a violation of any requirement of the POTW's NPDES permit (including an increase in the magnitude or duration of a violation) or, of the prevention of sewage sludge use or disposal in compliance with the following statutory provisions and regulations or permits issued thereunder (or more stringent state or local regulations): Section 405 of the Clean Water Act, the Solid Waste Disposal Act (SWDA) (including Title II, more commonly referred to as the Resource Conservation and Recovery Act (RCRA), and including state regulations contained in any state sludge management plan prepared pursuant to Subtitle D of the SWDA), the Clean Air Act, the Toxic Substances Control Act, and the Marine Protection, Research and Sanctuaries Act. [This definition does not apply to sample matrix interference].

Land application means spraying or spreading biosolids or a biosolids derivative onto the land surface, injecting below the land surface, or incorporating into the soil so that the biosolids or biosolids derivative can either condition the soil or fertilize crops or vegetation grown in the soil.

LC_{50} means a statistically or graphically estimated concentration that is expected to be lethal to 50% of a group of organisms under specified conditions.

Maximum acceptable toxicant concentration (MATC) means the concentration obtained by calculating the geometric mean of the lower and upper chronic limits from a chronic test. A lower chronic limit is the highest tested concentration that did not cause the occurrence of a specific adverse effect. An upper chronic limit is the lowest tested concentration which did cause the occurrence of a specific adverse effect and above which all tested concentrations caused such an occurrence.

Maximum extent practicable means implementation of best management practices by a public body to comply with an approved storm water management program as required by a national permit for a municipal separate storm sewer system, in a manner that is environmentally beneficial, technically feasible, and within the public body's legal authority.

MGD means million gallons per day.

Monthly concentration is the sum of the daily concentrations determined during a reporting period divided by the number of daily concentrations determined. The calculated monthly concentration will be used to determine compliance with any maximum monthly concentration limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly concentration in the "AVERAGE" column under "QUALITY OR CONCENTRATION" on the DMR.

For minimum percent removal requirements, the monthly influent concentration and the monthly effluent concentration shall be determined. The calculated monthly percent removal, which is equal to 100 times the quantity [1 minus the quantity (monthly effluent concentration divided by the monthly influent concentration)], shall be reported in the "MINIMUM" column under "QUALITY OR CONCENTRATION" on the DMRs.

Monthly loading is the sum of the daily loadings of a parameter divided by the number of daily loadings determined during a reporting period. The calculated monthly loading will be used to determine compliance with any maximum monthly loading limitations. Days with no discharge shall not be used to determine the value. When required by the permit, report the calculated monthly loading in the "AVERAGE" column under "QUANTITY OR LOADING" on the DMR.

Monthly monitoring frequency refers to a calendar month. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

PART II

Section A. Definitions

Municipal separate storm sewer means a conveyance or system of conveyances designed or used for collecting or conveying storm water which is not a combined sewer and which is not part of a publicly-owned treatment works as defined in the Code of Federal Regulations at 40 CFR 122.2.
Municipal separate storm sewer system (MS4) means all separate storm sewers that are owned or operated by the United States, a state, city, village, township, county, district, association, or other public body created by or pursuant to state law, having jurisdiction over disposal of sewage, industrial wastes, storm water, or other wastes, including special districts under state law, such as a sewer district, flood control district, or drainage district, or similar entity, or a designated or approved management agency under Section 208 of the Federal Act that discharges to the waters of the state. This term includes systems similar to separate storm sewer systems in municipalities, such as systems at military bases, large hospital or prison complexes, and highways and other thoroughfares. The term does not include separate storm sewers in very discrete areas, such as individual buildings.

National Pretreatment Standards are the regulations promulgated by or to be promulgated by the Federal Environmental Protection Agency pursuant to Section 307(b) and (c) of the Federal Act. The standards establish nationwide limits for specific industrial categories for discharge to a POTW.

No observed adverse effect level (NOAEL) means the highest tested dose or concentration of a substance which results in no observed adverse effect in exposed test organisms where higher doses or concentrations result in an adverse effect.

Noncontact cooling water is water used for cooling which does not come into direct contact with any raw material, intermediate product, by-product, waste product or finished product.

Nondomestic user is any discharger to a POTW that discharges wastes other than or in addition to water-carried wastes from toilet, kitchen, laundry, bathing or other facilities used for household purposes.

Outfall is the location at which a point source discharge enters the surface waters of the state.

Part 91 agency means an agency that is designated by a county board of commissioners pursuant to the provisions of section 9105 of Part 91 of the NREPA; an agency that is designated by a city, village, or township in accordance with the provisions of section 9106 of Part 91 of the NREPA; or the Department for soil erosion and sedimentation activities under Part 615, Part 631, or Part 632 pursuant to the provisions of section 9115 of Part 91 of the NREPA.

Part 91 permit means a soil erosion and sedimentation control permit issued by a Part 91 agency pursuant to the provisions of Part 91 of the NREPA.

Partially treated sewage is any sewage, sewage and storm water, or sewage and wastewater, from domestic or industrial sources that is treated to a level less than that required by the permittee's National Pollutant Discharge Elimination System permit, or that is not treated to national secondary treatment standards for wastewater, including discharges to surface waters from retention treatment facilities.

Point of discharge is the location of a point source discharge where storm water is discharged directly into a separate storm sewer system.

Point source discharge means a discharge from any discernible, confined, discrete conveyance, including but not limited to any pipe, ditch, channel, tunnel, conduit, well, discrete fissure, container, or rolling stock. Changing the surface of land or establishing grading patterns on land will result in a point source discharge where the runoff from the site is ultimately discharged to waters of the state.

Polluting material means any material, in solid or liquid form, identified as a polluting material under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

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Section A. Definitions

POTW is a publicly owned treatment work.

Pretreatment is reducing the amount of pollutants, eliminating pollutants, or altering the nature of pollutant properties to a less harmful state prior to discharge into a public sewer. The reduction or alteration can be by physical, chemical, or biological processes, process changes, or by other means. Dilution is not considered pretreatment unless expressly authorized by an applicable National Pretreatment Standard for a particular industrial category.
Public (as used in the MS4 individual permit) means all persons who potentially could affect the authorized storm water discharges, including, but not limited to, residents, visitors to the area, public employees, businesses, industries, and construction contractors and developers.

Public body means the United States; the state of Michigan; a city, village, township, county, school district, public college or university, or single-purpose governmental agency; or any other body which is created by federal or state statute or law.

Qualified Personnel means an individual who meets qualifications acceptable to the Department and who is authorized by an Industrial Storm Water Certified Operator to collect the storm water sample.

Qualifying storm event means a storm event causing greater than 0.1 inch of rainfall and occurring at least 72 hours after the previous measurable storm event that also caused greater than 0.1 inch of rainfall. Upon request, the Department may approve an alternate definition meeting the condition of a qualifying storm event.

Quantification level means the measurement of the concentration of a contaminant obtained by using a specified laboratory procedure calculated at a specified concentration above the detection level. It is considered the lowest concentration at which a particular contaminant can be quantitatively measured using a specified laboratory procedure for monitoring of the contaminant.

Quarterly monitoring frequency refers to a three month period, defined as January through March, April through June, July through September, and October through December. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

Regional Administrator is the Region 5 Administrator, U.S. EPA, located at R-19J, 77 W. Jackson Blvd., Chicago, Illinois 60604.

Regulated area means the permittee's urbanized area, where urbanized area is defined as a place and its adjacent densely-populated territory that together have a minimum population of 50,000 people as defined by the United States Bureau of the Census and as determined by the latest available decennial census.

Secondary containment structure means a unit, other than the primary container, in which significant materials are packaged or held, which is required by State or Federal law to prevent the escape of significant materials by gravity into sewers, drains, or otherwise directly or indirectly into any sewer system or to the surface or ground waters of this state.

Separate storm sewer system means a system of drainage, including, but not limited to, roads, catch basins, curbs, gutters, parking lots, ditches, conduits, pumping devices, or man-made channels, which is not a combined sewer where storm water mixes with sanitary wastes, and is not part of a POTW.

Significant industrial user is a nondomestic user that: 1) is subject to Categorical Pretreatment Standards under 40 CFR 403.6 and 40 CFR Chapter I, Subchapter N; or 2) discharges an average of 25,000 gallons per day or more of process wastewater to a POTW (excluding sanitary, noncontact cooling and boiler blowdown wastewater); contributes a process waste stream which makes up five (5) percent or more of the average dry weather hydraulic or organic capacity of the POTW treatment plant; or is designated as such by the permittee as defined in 40 CFR 403.12(a) on the basis that the industrial user has a reasonable potential for adversely

PART II

Section A. Definitions

affecting the POTW's treatment plant operation or violating any pretreatment standard or requirement (in accordance with 40 CFR 403.8(f)(6)).

Significant materials Significant Materials means any material which could degrade or impair water quality, including but not limited to: raw materials; fuels; solvents, detergents, and plastic pellets; finished materials such as metallic products; hazardous substances designated under Section 101(14) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) (see 40 CFR 372.65); any chemical the facility is required to report pursuant to Section 313 of Emergency Planning and Community Right-to-Know Act (EPCRA); polluting materials as identified under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code); Hazardous Wastes as defined in Part 111 of the NREPA; fertilizers; pesticides; and waste products such as ashes, slag, and sludge that have the potential to be released with storm water discharges.

Significant spills and significant leaks means any release of a polluting material reportable under the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code).

Special-use area means secondary containment structures required by state or federal law; lands on Michigan's List of Sites of Environmental Contamination pursuant to Part 201, Environmental Remediation, of the NREPA; and/or areas with other activities that may contribute pollutants to the storm water for which the Department determines monitoring is needed.

Stoichiometric means the quantity of a reagent calculated to be necessary and sufficient for a given chemical reaction.

Storm water means storm water runoff, snow melt runoff, surface runoff and drainage, and non-storm water included under the conditions of this permit.

Storm water discharge point is the location where the point source discharge of storm water is directed to surface waters of the state or to a separate storm sewer. It includes the location of all point source discharges where storm water exits the facility, including *outfalls* which discharge directly to surface waters of the state, and *points of discharge* which discharge directly into separate storm sewer systems.

SWPPP means the Storm Water Pollution Prevention Plan prepared in accordance with this permit.

Tier I value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier I toxicity database.

Tier II value means a value for aquatic life, human health or wildlife calculated under R 323.1057 of the Water Quality Standards using a tier II toxicity database.

Total maximum daily loads (TMDLs) are required by the Federal Act for waterbodies that do not meet water quality standards. TMDLs represent the maximum daily load of a pollutant that a waterbody can assimilate and meet water quality standards, and an allocation of that load among point sources, nonpoint sources, and a margin of safety.

Toxicity reduction evaluation (TRE) means a site-specific study conducted in a stepwise process designed to identify the causative agents of effluent toxicity, isolate the sources of toxicity, evaluate the effectiveness of toxicity control options, and then confirm the reduction in effluent toxicity.

Water Quality Standards means the Part 4 Water Quality Standards promulgated pursuant to Part 31 of the NREPA, being R 323.1041 through R 323.1117 of the Michigan Administrative Code.

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Section A. Definitions

Weekly monitoring frequency refers to a calendar week which begins on Sunday and ends on Saturday. When required by this permit, an analytical result, reading, value or observation shall be reported for that period if a discharge occurs during that period.

WWSL is a wastewater stabilization lagoon.

WWSL discharge event is a discrete occurrence during which effluent is discharged to the surface water up to 10 days of a consecutive 14 day period.

3-portion composite sample is a sample consisting of three equal-volume grab samples collected at equal intervals over an 8-hour period.

7-day concentration
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily concentrations determined. If the number of daily concentrations determined during the WWSL discharge event is less than 7 days, the number of actual daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations. When required by the permit, report the maximum calculated 7-day concentration for the WWSL discharge event in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred.

FOR ALL OTHER DISCHARGES – The 7-day concentration is the sum of the daily concentrations determined during any 7 consecutive days in a reporting month divided by the number of daily concentrations determined. If the number of daily concentrations determined is less than 7, the actual number of daily concentrations determined shall be used for the calculation. The calculated 7-day concentration will be used to determine compliance with any maximum 7-day concentration limitations in the reporting month. When required by the permit, report the maximum calculated 7-day concentration for the month in the "MAXIMUM" column under "QUALITY OR CONCENTRATION" on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

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Section A. Definitions

7-day loading
FOR WWSLs THAT COLLECT AND STORE WASTEWATER AND ARE AUTHORIZED TO DISCHARGE ONLY IN THE SPRING AND/OR FALL ON AN INTERMITTENT BASIS – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days of discharge during a WWSL discharge event divided by the number of daily loadings determined. If the number of daily loadings determined during the WWSL discharge event is less than 7 days, the number of actual daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations. When required by the permit, report the maximum calculated 7-day loading for the WWSL discharge event in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMR. If the WWSL discharge event was partially in each of two months, the value shall be reported on the DMR of the month in which the last day of discharge occurred

FOR ALL OTHER DISCHARGES – The 7-day loading is the sum of the daily loadings determined during any 7 consecutive days in a reporting month divided by the number of daily loadings determined. If the number of daily loadings determined is less than 7, the actual number of daily loadings determined shall be used for the calculation. The calculated 7-day loading will be used to determine compliance with any maximum 7-day loading limitations in the reporting month. When required by the permit, report the maximum calculated 7-day loading for the month in the "MAXIMUM" column under "QUANTITY OR LOADING" on the DMR. The first 7-day calculation shall be made on day 7 of the reporting month, and the last calculation shall be made on the last day of the reporting month.

24-hour composite sample is a flow-proportioned composite sample consisting of hourly or more frequent portions that are taken over a 24-hour period. A time-proportioned composite sample may be used upon approval of the Department if the permittee demonstrates it is representative of the discharge.

PART II

Section B. Monitoring Procedures

1. Representative Samples

Samples and measurements taken as required herein shall be representative of the volume and nature of the monitored discharge.

2. Test Procedures

Test procedures for the analysis of pollutants shall conform to regulations promulgated pursuant to Section 304(h) of the Federal Act (40 CFR Part 136 – Guidelines Establishing Test Procedures for the Analysis of Pollutants), unless specified otherwise in this permit. **Test procedures used shall be sufficiently sensitive to determine compliance with applicable effluent limitations**. Requests to use test procedures not promulgated under 40 CFR Part 136 for pollutant monitoring required by this permit shall be made in accordance with the Alternate Test Procedures regulations specified in 40 CFR 136.4. These requests shall be submitted to the Section Manager of the Permits Section, Water Resources Division, Michigan Department of Environment, Great Lakes, and Energy, P.O. Box 30458, Lansing, Michigan, 48909-7958. The permittee may use such procedures upon approval.

The permittee shall periodically calibrate and perform maintenance procedures on all analytical instrumentation at intervals to ensure accuracy of measurements. The calibration and maintenance shall be performed as part of the permittee's laboratory Quality Control/Quality Assurance program.

3. Instrumentation

The permittee shall periodically calibrate and perform maintenance procedures on all monitoring instrumentation at intervals to ensure accuracy of measurements.

4. Recording Results

For each measurement or sample taken pursuant to the requirements of this permit, the permittee shall record the following information: 1) the exact place, date, and time of measurement or sampling; 2) the person(s) who performed the measurement or sample collection; 3) the dates the analyses were performed; 4) the person(s) who performed the analyses; 5) the analytical techniques or methods used; 6) the date of and person responsible for equipment calibration; and 7) the results of all required analyses.

5. Records Retention

All records and information resulting from the monitoring activities required by this permit including all records of analyses performed and calibration and maintenance of instrumentation and recordings from continuous monitoring instrumentation shall be retained for a minimum of three (3) years, or longer if requested by the Regional Administrator or the Department.

PART II

Section C. Reporting Requirements

1. Start-up Notification

If the permittee will not discharge during the first 60 days following the effective date of this permit, the permittee shall notify the Department within 14 days following the effective date of this permit, and then 60 days prior to the commencement of the discharge.

2. Submittal Requirements for Self-Monitoring Data

Part 31 of the NREPA (specifically Section 324.3110(7)); and R 323.2155(2) of Part 21, Wastewater Discharge Permits, promulgated under Part 31 of the NREPA, allow the Department to specify the forms to be utilized for reporting the required self-monitoring data. Unless instructed on the effluent limitations page to conduct "Retained Self-Monitoring," the permittee shall submit self-monitoring data via the Department's MiWaters system.

The permittee shall utilize the information provided on the MiWaters website, located at https://miwaters.deq.state.mi.us, to access and submit the electronic forms. Both monthly summary and daily data shall be submitted to the Department no later than the 20th day of the month following each month of the authorized discharge period(s). The permittee may be allowed to submit the electronic forms after this date if the Department has granted an extension to the submittal date.

3. Retained Self-Monitoring Requirements

If instructed on the effluent limits page (or otherwise authorized by the Department in accordance with the provisions of this permit) to conduct retained self-monitoring, the permittee shall maintain a year-to-date log of retained self-monitoring results and, upon request, provide such log for inspection to the staff of the Department. Retained self-monitoring results are public information and shall be promptly provided to the public upon request.

The permittee shall certify, in writing, to the Department, on or before January 10th (April 1st for animal feeding operation facilities) of each year, that: 1) all retained self-monitoring requirements have been complied with and a year-to-date log has been maintained; and 2) the application on which this permit is based still accurately describes the discharge. With this annual certification, the permittee shall submit a summary of the previous year's monitoring data. The summary shall include maximum values for samples to be reported as daily maximums and/or monthly maximums and minimum values for any daily minimum samples.

Retained self-monitoring may be denied to a permittee by notification in writing from the Department. In such cases, the permittee shall submit self-monitoring data in accordance with Part II.C.2., above. Such a denial may be rescinded by the Department upon written notification to the permittee. Reissuance or modification of this permit or reissuance or modification of an individual permittee's authorization to discharge shall not affect previous approval or denial for retained self-monitoring unless the Department provides notification in writing to the permittee.

4. Additional Monitoring by Permittee

If the permittee monitors any pollutant at the location(s) designated herein more frequently than required by this permit, using approved analytical methods as specified above, the results of such monitoring shall be included in the calculation and reporting of the values required in the Discharge Monitoring Report. Such increased frequency shall also be indicated.

PART II

Section C. Reporting Requirements

Monitoring required pursuant to Part 41 of the NREPA or Rule 35 of the Mobile Home Park Commission Act (Act 96 of the Public Acts of 1987) for assurance of proper facility operation shall be submitted as required by the Department.

5. Compliance Dates Notification

Within 14 days of every compliance date specified in this permit, the permittee shall submit a *written* notification to the Department indicating whether or not the particular requirement was accomplished. If the requirement was not accomplished, the notification shall include an explanation of the failure to accomplish the requirement, actions taken or planned by the permittee to correct the situation, and an estimate of when the requirement will be accomplished. If a written report is required to be submitted by a specified date and the permittee accomplishes this, a separate written notification is not required.

6. Noncompliance Notification

Compliance with all applicable requirements set forth in the Federal Act, Parts 31 and 41 of the NREPA, and related regulations and rules is required. All instances of noncompliance shall be reported as follows:

a. 24-Hour Reporting
Any noncompliance which may endanger health or the environment (including maximum and/or minimum daily concentration discharge limitation exceedances) shall be reported, verbally, within 24 hours from the time the permittee becomes aware of the noncompliance. A written submission shall also be provided within five (5) days.

b. Other Reporting
The permittee shall report, in writing, all other instances of noncompliance not described in a. above at the time monitoring reports are submitted; or, in the case of retained self-monitoring, within five (5) days from the time the permittee becomes aware of the noncompliance.

Written reporting shall include: 1) a description of the discharge and cause of noncompliance; and 2) the period of noncompliance, including exact dates and times, or, if not yet corrected, the anticipated time the noncompliance is expected to continue, and the steps taken to reduce, eliminate and prevent recurrence of the noncomplying discharge.

7. Spill Notification

The permittee shall immediately report any release of any polluting material which occurs to the surface waters or groundwaters of the state, unless the permittee has determined that the release is not in excess of the threshold reporting quantities specified in the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code), by calling the Department at the number indicated on the second page of this permit (or, if this is a general permit, on the COC); or, if the notice is provided after regular working hours, call the Department's 24-hour Pollution Emergency Alerting System telephone number, 1-800-292-4706 (calls from **out-of-state** dial 1-517-373-7660).

Within ten (10) days of the release, the permittee shall submit to the Department a full written explanation as to the cause of the release, the discovery of the release, response (clean-up and/or recovery) measures taken, and preventive measures taken or a schedule for completion of measures to be taken to prevent reoccurrence of similar releases.

PART II

Section C. Reporting Requirements

8. Upset Noncompliance Notification

If a process "upset" (defined as an exceptional incident in which there is unintentional and temporary noncompliance with technology based permit effluent limitations because of factors beyond the reasonable control of the permittee) has occurred, the permittee who wishes to establish the affirmative defense of upset, shall notify the Department by telephone within 24 hours of becoming aware of such conditions; and within five (5) days, provide in writing, the following information:

a. that an upset occurred and that the permittee can identify the specific cause(s) of the upset;

b. that the permitted wastewater treatment facility was, at the time, being properly operated and maintained (note that an upset does not include noncompliance to the extent caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, or careless or improper operation); and

c. that the permittee has specified and taken action on all responsible steps to minimize or correct any adverse impact in the environment resulting from noncompliance with this permit.

No determination made during administrative review of claims that noncompliance was caused by upset, and before an action for noncompliance, is final administrative action subject to judicial review.

In any enforcement proceedings, the permittee, seeking to establish the occurrence of an upset, has the burden of proof.

9. Bypass Prohibition and Notification

a. Bypass Prohibition
Bypass is prohibited, and the Department may take an enforcement action, unless:

1) bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

2) there were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate backup equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass; and

3) the permittee submitted notices as required under 9.b. or 9.c. below.

b. Notice of Anticipated Bypass
If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least ten (10) days before the date of the bypass, and provide information about the anticipated bypass as required by the Department. The Department may approve an anticipated bypass, after considering its adverse effects, if it will meet the three (3) conditions listed in 9.a. above.

c. Notice of Unanticipated Bypass
The permittee shall submit notice to the Department of an unanticipated bypass by calling the Department at the number indicated on the second page of this permit (if the notice is provided after regular working hours, use the following number: 1-800-292-4706) as soon as possible, but no later than 24 hours from the time the permittee becomes aware of the circumstances.

PART II

Section C. Reporting Requirements

d. Written Report of Bypass
A written submission shall be provided within five (5) working days of commencing any bypass to the Department, and at additional times as directed by the Department. The written submission shall contain a description of the bypass and its cause; the period of bypass, including exact dates and times, and if the bypass has not been corrected, the anticipated time it is expected to continue; steps taken or planned to reduce, eliminate, and prevent reoccurrence of the bypass; and other information as required by the Department.

e. Bypass Not Exceeding Limitations
The permittee may allow any bypass to occur which does not cause effluent limitations to be exceeded, but only if it also is for essential maintenance to ensure efficient operation. These bypasses are not subject to the provisions of 9.a., 9.b., 9.c., and 9.d., above. This provision does not relieve the permittee of any notification responsibilities under Part II.C.11. of this permit.

f. Definitions

1) Bypass means the intentional diversion of waste streams from any portion of a treatment facility.

2) Severe property damage means substantial physical damage to property, damage to the treatment facilities which causes them to become inoperable, or substantial and permanent loss of natural resources which can reasonably be expected to occur in the absence of a bypass. Severe property damage does not mean economic loss caused by delays in production.

10. Bioaccumulative Chemicals of Concern (BCC)

Consistent with the requirements of R 323.1098 and R 323.1215 of the Michigan Administrative Code, the permittee is prohibited from undertaking any action that would result in a lowering of water quality from an increased loading of a BCC unless an increased use request and antidegradation demonstration have been submitted and approved by the Department.

11. Notification of Changes in Discharge

The permittee shall notify the Department, in writing, as soon as possible but no later than 10 days of knowing, or having reason to believe, that any activity or change has occurred or will occur which would result in the discharge of: 1) detectable levels of chemicals on the current Michigan Critical Materials Register, priority pollutants or hazardous substances set forth in 40 CFR 122.21, Appendix D, or the Pollutants of Initial Focus in the Great Lakes Water Quality Initiative specified in 40 CFR 132.6, Table 6, which were not acknowledged in the application or listed in the application at less than detectable levels; 2) detectable levels of any other chemical not listed in the application or listed at less than detection, for which the application specifically requested information; or 3) any chemical at levels greater than five times the average level reported in the complete application (see the first page of this permit, for the date(s) the complete application was submitted). Any other monitoring results obtained as a requirement of this permit shall be reported in accordance with the compliance schedules.

PART II

Section C. Reporting Requirements

12. Changes in Facility Operations

Any anticipated action or activity, including but not limited to facility expansion, production increases, or process modification, which will result in new or increased loadings of pollutants to the receiving waters must be reported to the Department by a) submission of an increased use request (application) and all information required under R 323.1098 (Antidegradation) of the Water Quality Standards or b) by notice if the following conditions are met: 1) the action or activity will not result in a change in the types of wastewater discharged or result in a greater quantity of wastewater than currently authorized by this permit; 2) the action or activity will not result in violations of the effluent limitations specified in this permit; 3) the action or activity is not prohibited by the requirements of Part II.C.10.; and 4) the action or activity will not require notification pursuant to Part II.C.11. Following such notice, the permit or, if applicable, the facility's COC may be modified according to applicable laws and rules to specify and limit any pollutant not previously limited.

13. Transfer of Ownership or Control

In the event of any change in control or ownership of facilities from which the authorized discharge emanates, the permittee shall submit to the Department 30 days prior to the actual transfer of ownership or control a written agreement between the current permittee and the new permittee containing: 1) the legal name and address of the new owner; 2) a specific date for the effective transfer of permit responsibility, coverage and liability; and 3) a certification of the continuity of or any changes in operations, wastewater discharge, or wastewater treatment.

If the new permittee is proposing changes in operations, wastewater discharge, or wastewater treatment, the Department may propose modification of this permit in accordance with applicable laws and rules.

14. Operations and Maintenance Manual

For wastewater treatment facilities that serve the public (and are thus subject to Part 41 of the NREPA), Section 4104 of Part 41 and associated Rule 2957 of the Michigan Administrative Code allow the Department to require an Operations and Maintenance (O&M) Manual from the facility. An up-to-date copy of the O&M Manual shall be kept at the facility and shall be provided to the Department upon request. The Department may review the O&M Manual in whole or in part at its discretion and require modifications to it if portions are determined to be inadequate.

At a minimum, the O&M Manual shall include the following information: permit standards; descriptions and operation information for all equipment; staffing information; laboratory requirements; record keeping requirements; a maintenance plan for equipment; an emergency operating plan; safety program information; and copies of all pertinent forms, as-built plans, and manufacturer's manuals.

Certification of the existence and accuracy of the O&M Manual shall be submitted to the Department at least sixty days prior to start-up of a new wastewater treatment facility. Recertification shall be submitted sixty days prior to start-up of any substantial improvements or modifications made to an existing wastewater treatment facility.

PART II

Section C. Reporting Requirements

15. Signatory Requirements

All applications, reports, or information submitted to the Department in accordance with the conditions of this permit and that require a signature shall be signed and certified as described in the Federal Act and the NREPA.

The Federal Act provides that any person who knowingly makes any false statement, representation, or certification in any record or other document submitted or required to be maintained under this permit, including monitoring reports or reports of compliance or noncompliance, shall, upon conviction, be punished by a fine of not more than $10,000 per violation, or by imprisonment for not more than 6 months per violation, or by both.

The NREPA (Section 3115(2)) provides that a person who at the time of the violation knew or should have known that he or she discharged a substance contrary to this part, or contrary to a permit, COC, or order issued or rule promulgated under this part, or who intentionally makes a false statement, representation, or certification in an application for or form pertaining to a permit or COC or in a notice or report required by the terms and conditions of an issued permit or COC, or who intentionally renders inaccurate a monitoring device or record required to be maintained by the Department, is guilty of a felony and shall be fined not less than $2,500.00 or more than $25,000.00 for each violation. The court may impose an additional fine of not more than $25,000.00 for each day during which the unlawful discharge occurred. If the conviction is for a violation committed after a first conviction of the person under this subsection, the court shall impose a fine of not less than $25,000.00 per day and not more than $50,000.00 per day of violation. Upon conviction, in addition to a fine, the court in its discretion may sentence the defendant to imprisonment for not more than 2 years or impose probation upon a person for a violation of this part. With the exception of the issuance of criminal complaints, issuance of warrants, and the holding of an arraignment, the circuit court for the county in which the violation occurred has exclusive jurisdiction. However, the person shall not be subject to the penalties of this subsection if the discharge of the effluent is in conformance with and obedient to a rule, order, permit, or COC of the Department. In addition to a fine, the attorney general may file a civil suit in a court of competent jurisdiction to recover the full value of the injuries done to the natural resources of the state and the costs of surveillance and enforcement by the state resulting from the violation.

16. Electronic Reporting

Upon notice by the Department that electronic reporting tools are available for specific reports or notifications, the permittee shall submit electronically all such reports or notifications as required by this permit.

PART II

Section D. Management Responsibilities

1. Duty to Comply

All discharges authorized herein shall be consistent with the terms and conditions of this permit. The discharge of any pollutant identified in this permit, more frequently than, or at a level in excess of, that authorized, shall constitute a violation of the permit.

It is the duty of the permittee to comply with all the terms and conditions of this permit. Any noncompliance with the Effluent Limitations, Special Conditions, or terms of this permit constitutes a violation of the NREPA and/or the Federal Act and constitutes grounds for enforcement action; for permit or Certificate of Coverage (COC) termination, revocation and reissuance, or modification; or denial of an application for permit or COC renewal.

It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

2. Operator Certification

The permittee shall have the waste treatment facilities under direct supervision of an operator certified at the appropriate level for the facility certification by the Department, as required by Sections 3110 and 4104 of the NREPA. Permittees authorized to discharge storm water shall have the storm water treatment and/or control measures under direct supervision of a storm water operator certified by the Department, as required by Section 3110 of the NREPA.

3. Facilities Operation

The permittee shall, at all times, properly operate and maintain all treatment or control facilities or systems installed or used by the permittee to achieve compliance with the terms and conditions of this permit. Proper operation and maintenance includes adequate laboratory controls and appropriate quality assurance procedures.

4. Power Failures

In order to maintain compliance with the effluent limitations of this permit and prevent unauthorized discharges, the permittee shall either:

a. provide an alternative power source sufficient to operate facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit; or

b. upon the reduction, loss, or failure of one or more of the primary sources of power to facilities utilized by the permittee to maintain compliance with the effluent limitations and conditions of this permit, the permittee shall halt, reduce or otherwise control production and/or all discharge in order to maintain compliance with the effluent limitations and conditions of this permit.

5. Adverse Impact

The permittee shall take all reasonable steps to minimize or prevent any adverse impact to the surface waters or groundwaters of the state resulting from noncompliance with any effluent limitation specified in this permit including, but not limited to, such accelerated or additional monitoring as necessary to determine the nature and impact of the discharge in noncompliance.

PART II

Section D. Management Responsibilities

6. Containment Facilities

The permittee shall provide facilities for containment of any accidental losses of polluting materials in accordance with the requirements of the Part 5 Rules (R 324.2001 through R 324.2009 of the Michigan Administrative Code). For a Publicly Owned Treatment Work (POTW), these facilities shall be approved under Part 41 of the NREPA.

7. Waste Treatment Residues

Residuals (i.e. solids, sludges, biosolids, filter backwash, scrubber water, ash, grit, or other pollutants or wastes) removed from or resulting from treatment or control of wastewaters, including those that are generated during treatment or left over after treatment or control has ceased, shall be disposed of in an environmentally compatible manner and according to applicable laws and rules. These laws may include, but are not limited to, the NREPA, Part 31 for protection of water resources, Part 55 for air pollution control, Part 111 for hazardous waste management, Part 115 for solid waste management, Part 121 for liquid industrial wastes, Part 301 for protection of inland lakes and streams, and Part 303 for wetlands protection. Such disposal shall not result in any unlawful pollution of the air, surface waters or groundwaters of the state.

8. Right of Entry

The permittee shall allow the Department, any agent appointed by the Department, or the Regional Administrator, upon the presentation of credentials and, for animal feeding operation facilities, following appropriate biosecurity protocols:

a. to enter upon the permittee's premises where an effluent source is located or any place in which records are required to be kept under the terms and conditions of this permit; and

b. at reasonable times to have access to and copy any records required to be kept under the terms and conditions of this permit; to inspect process facilities, treatment works, monitoring methods and equipment regulated or required under this permit; and to sample any discharge of pollutants.

9. Availability of Reports

Except for data determined to be confidential under Section 308 of the Federal Act and Rule 2128 (R 323.2128 of the Michigan Administrative Code), all reports prepared in accordance with the terms of this permit, shall be available for public inspection at the offices of the Department and the Regional Administrator. As required by the Federal Act, effluent data shall not be considered confidential. Knowingly making any false statement on any such report may result in the imposition of criminal penalties as provided for in Section 309 of the Federal Act and Sections 3112, 3115, 4106 and 4110 of the NREPA.

10. Duty to Provide Information

The permittee shall furnish to the Department, within a reasonable time, any information which the Department may request to determine whether cause exists for modifying, revoking and reissuing, or terminating this permit or the facility's COC, or to determine compliance with this permit. The permittee shall also furnish to the Department, upon request, copies of records required to be kept by this permit.

Where the permittee becomes aware that it failed to submit any relevant facts in a permit application, or submitted incorrect information in a permit application or in any report to the Department, it shall promptly submit such facts or information.

PART II

Section E. Activities Not Authorized by This Permit

1. Discharge to the Groundwaters

This permit does not authorize any discharge to the groundwaters. Such discharge may be authorized by a groundwater discharge permit issued pursuant to the NREPA.

2. POTW Construction

This permit does not authorize or approve the construction or modification of any physical structures or facilities at a POTW. Approval for the construction or modification of any physical structures or facilities at a POTW shall be by permit issued under Part 41 of the NREPA.

3. Civil and Criminal Liability

Except as provided in permit conditions on "Bypass" (Part II.C.9. pursuant to 40 CFR 122.41(m)), nothing in this permit shall be construed to relieve the permittee from civil or criminal penalties for noncompliance, whether or not such noncompliance is due to factors beyond the permittee's control, such as accidents, equipment breakdowns, or labor disputes.

4. Oil and Hazardous Substance Liability

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties to which the permittee may be subject under Section 311 of the Federal Act except as are exempted by federal regulations.

5. State Laws

Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation under authority preserved by Section 510 of the Federal Act.

6. Property Rights

The issuance of this permit does not convey any property rights in either real or personal property, or any exclusive privileges, nor does it authorize violation of any federal, state or local laws or regulations, nor does it obviate the necessity of obtaining such permits, including any other Department of Environment, Great Lakes, and Energy permits, or approvals from other units of government as may be required by law.

Attachment G

MPSC Case No, U-21090, Order approving settlement
(June 23, 2022)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

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

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

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

ORDER APPROVING SETTLEMENT AGREEMENT

I. Procedural History

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

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

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

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

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

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

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

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

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

II. Applicable Law

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

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

III. Proposed Settlement Agreement

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

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

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

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

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

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

> a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO [Midcontinent Independent System Operator, Inc.] Zone 7 starting in the 2025 Planning Year;
>
> b. The One-Time Solicitation will include two all source tranches:
>
> > i. The first tranche will seek up to 500 ZRCs [zonal resource credits] of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs [power purchase agreements] with terms up to 10 years. This tranche will seek dispatchable, nonintermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and
> >
> > ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the OneTime Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs [requests for proposals] and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.
>
> c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the OneTime Solicitation;
>
> > i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated 7 with the project(s) that

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

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

Id., pp. 6-7.

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

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

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

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

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

IV. Evidentiary Record

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

A. Direct Testimony

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

MNS and CUB presented the direct testimony of Douglas B. Jester. Mr. Jester testifies that the settlement agreement is in the public interest and recommends that the Commission approve the settlement agreement. Mr. Jester opines that "retiring the entire Campbell plant will benefit both customers and the environment and is therefore in the public interest." 10 Tr 4327. Mr. Jester notes that no party in this case opposed the retirement of Campbell Units 1 and 2 and adds that the ALJ also recommended approval of these retirements. Mr. Jester posits that "[t]he Campbell plant has a greater carbon impact than any other resource owned by [Consumers], and its retirement is critical to meeting state and federal climate goals, including the Michigan Healthy Climate Plan." 10 Tr 4327 (footnote omitted). Mr. Jester presents tables compiling Michigan's greenhouse gas emissions and the associated goals from the MI Healthy Climate Plan to

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

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

Mr. Jester adds that because the Campbell plant emits other pollutants, such as sulfur dioxide (SO_2), nitrogen oxide (NO_x), and particulate matter ($PM_{2.5}$), the retirement of the entire Campbell plant is likely to have health benefits beyond those of reducing the company's carbon output. 10 Tr 4327.

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

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

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

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

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

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

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

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

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

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

Mr. Jester provides that "[p]aragraph 4(i) of the settlement [agreement] provides that Karn units 3-4 will not retire in 2023 but instead will continue operating and retire on or before their previously planned retirement date of May 31, 2031, absent extraordinary circumstances." 10 Tr 4334. Mr. Jester posits that Karn Units 3 and 4 "provide substantial capacity but operate infrequently." 10 Tr 4334. Mr. Jester testifies that "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements [PRMR] by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. Further, Mr. Jester notes that Karn Units 3 and 4 staying online supports resource adequacy in MISO Zone 7 by maintaining these additional ZRCs. Mr. Jester testifies that keeping Karn Units 3 and 4 in operation removes the "unrecovered net book value from the total balance of the regulatory asset that Consumers seeks . . . lowering the costs of the regulatory asset for customers." 10 Tr 4334-4335.

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

> Consumers has taken a very firm position that it will not retire Campbell in 2025 without being able to recover a return of and on the unrecovered balance. Therefore, it was necessary for the other parties to agree with a regulatory asset based on WACC for this settlement [agreement] to occur and to facilitate Consumers' permanent exit from coal generation three years from now.

10 Tr 4335. Mr. Jester notes, however, that "setting the ROE [return on equity] at 9.0% for the calculation of the WACC on the regulatory asset is a significant compromise for Consumers, as that figure is substantially lower than the authorized ROE of 9.9% that the Commission approved in Consumers Energy's last electric rate case, [Case No.] U-20963." 10 Tr 4335.

Mr. Jester posits that Consumers' low-income customer bill assistance donations are a beneficial settlement term. Mr. Jester provides that "Consumers agreed in paragraph 13 of the settlement [agreement] to donate funds to its low-income bill assistance programs." 10 Tr 4336. Mr. Jester notes that these funds will not be recovered in rates. Specifically, "Consumers will donate $5 million in 2022 and $2 million per year for the rest of the term of the regulatory asset for the Campbell plant." 10 Tr 4336. Mr. Jester asserts that "[t]he need for additional low-income customer bill assistance has been demonstrated both in recent Consumers electric rate cases and in recent Consumers EWR cases, and recognized by the Commission in a variety of orders." 10 Tr 4336 (footnote omitted).

Mr. Jester provides that "[p]aragraph 9 of the settlement [agreement] requires Consumers to use commercially reasonable efforts to maintain the 50/50 split between owned resources and

PPAs for new solar procurements" that was first approved in the settlement agreement in Case No. U-20165. 10 Tr 4336. Mr. Jester also notes that paragraph 9 "creates an absolute cap of 60% on capacity that Consumers acquires for ownership in any annual solicitation, while setting no cap on the amount of new solar the Company may acquire via PPA" and "maintains the bar on Consumers affiliates participating in the PPA portion of the solicitations." 10 Tr 4337. Mr. Jester opines that "[t]he Commission found this allocation reasonable and in the public interest" in Consumers last IRP and that "this term maintains the essential components of that agreement." 10 Tr 4337. Mr. Jester posits that making a commercially reasonable efforts to maintain the 50/50 split "promotes competition among third-party developers which reduces customer costs" and "helps support the solar industry in Michigan." 10 Tr 4337. Mr. Jester notes that this provision of the settlement agreement is consistent with the ALJ's recommendations on the issue. 10 Tr 4337.

Mr. Jester testifies that paragraph 10 of the settlement agreement provides for an extension of the FCM approved in Case No. U-21065, Consumers' 2018 IRP. 10 Tr 4337. Mr. Jester opines that "[a]n FCM is a reasonable incentive for the Commission to authorize" given that "Consumers has substantially changed its business model by agreeing to shift its resource portfolio away from coal generation and toward solar generation, and by agreeing to procure the solar generation via competitive solicitations under which half of that capacity will be in the form of PPAs." 10 Tr 4338.

Mr. Jester provides that paragraph 16 of the settlement agreement "states that the parties agree in Consumers' next IRP to consider how transmission investments can improve reliability and access to economic sources of power from areas outside Zone 7." 10 Tr 4338. Mr. Jester supports the transmission provision as a reasonable and beneficial settlement term and notes that the ALJ's

decision "found that Consumers' transmission analysis in this case was deficient and did not meet the terms of the settlement agreement in [Case No.] U-21065." 10 Tr 4338-4339.

Mr. Jester supports the proposed battery storage investments outlined in the settlement agreement. Mr. Jester provides that the "parties agree to approval of a battery deployment program in paragraph 3 of the settlement agreement" as proposed in the principal rebuttal testimony in this case. 10 Tr 4339. Mr. Jester outlines that "Consumers proposed . . . to advance investment in 75 MW [megawatts] of battery storage resources. The settlement [agreement] reserves approval of the costs of the program to future electric rate cases." 10 Tr 4339. Mr. Jester posits that Consumers made the battery proposal in response to testimony from the Staff, MNS, and other parties that "called for acceleration of battery storage investments as part of Consumers' resource portfolio for this IRP." 10 Tr 4339. Mr. Jester notes that "battery deployment will provide another clean energy resource to bolster Consumers' maintenance of its PRMR and support resource adequacy in Zone 7." 10 Tr 4339.

Mr. Jester provides that in paragraph 14 of the settlement agreement, Consumers agrees "to collect further data on marginal line losses and to include marginal line losses and avoided transmission and distribution (T&D) costs in the evaluation of all distributed resources, including residential demand response, for its next IRP." 10 Tr 4340. Mr. Jester defers to testimony of CUB witness David Gard and MNS witness Chris Neme in explaining "the importance of these issues to the evaluation of EWR potential and DR potential for future IRPs." 10 Tr 4340.

Mr. Jester notes that paragraphs 17 and 18 of the settlement agreement contain provisions regarding an environmental justice analysis and community outreach for Consumers' next IRP. Mr. Jester supports these settlement terms and posits that "[t]he environmental justice analysis will provide vital information regarding the people and communities who bear disproportionate

impacts of electric generation activities—information that has been lacking in Michigan IRP cases up until now." 10 Tr 4341.

Finally, Mr. Jester provides that "[p]aragraph 7 of the settlement agreement requires Consumers to publicly file its community transition plans for the Campbell and Karn sites." 10 Tr 4341. Mr. Jester defers to testimony of MNS witness Tyler Comings regarding the need for public filing of transition plans. 10 Tr 4341.

Mr. Jester concludes that "[t]he settlement agreement in this case continues and significantly extends the progress of the settlement [agreement] in [Case No.] U-20165." 10 Tr 4341. Mr. Jester posits that the settlement agreement is "supported by the great weight of evidence in the record of this case and consistent with many of the findings and recommendations in the PFD." 10 Tr 4342. Thus, Mr. Jester recommends the Commission approve the proposed settlement agreement.

2. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

The CEOs presented the direct testimony of James Gignac, Senior Midwest Energy Analyst employed by the Union of Concerned Scientists. Mr. Gignac posits that the proposed settlement supports the public interest. Mr. Gignac posits that the settlement agreement "supports the public interest in three main ways: (1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company's next IRP." 10 Tr 4375.

Mr. Gignac avers that "Consumers approach of retiring all its coal-fired power plants by 2025 aligns with Governor Whitmer's MI Healthy Climate Plan's goal to phase out Michigan's remaining coal plants by 2030" and "the Company's plans to add 8,000 megawatts of solar by

2040 is an important step toward the MI Healthy Climate Plan's target for renewable energy to be providing 60 percent of Michigan's electricity generation by 2030." 10 Tr 4375.

Mr. Gignac posits that "the proposed settlement [agreement] helps reduce financial and public health costs related to Consumers' resource plan" because "the Company has agreed to a lower rate of return for its retiring coal plants and will commit tens of millions of dollars of shareholder funds to support bill assistance for lower-income customers." 10 Tr 4376. Mr. Gignac opines that expert testimony in this case "demonstrated the benefits of earlier coal plant retirements in the form of avoided negative health outcomes." 10 Tr 4376.

Finally, Mr. Gignac argues that commitments made by Consumers for its future IRPs "will ensure that additional information and perspectives are available to inform both the Company's assessment of its future resource options as well as Commission and stakeholder review of its proposals." 10 Tr 4376-4377. Mr. Gignac includes the agreement to model distributed generation as a resource, to conduct public health and environmental justice analyses, and to expand opportunities and forums for community input among the beneficial modeling and community engagement commitments made by Consumers. 10 Tr 4376-4377.

For the reasons outlined above, Mr. Gignac concludes that the Commission should approve the settlement agreement as it "represents a reasonable resolution of the issues . . . ." 10 Tr 4377.

3. Energy Michigan

Energy Michigan presented the direct testimony of Alexander J. Zakem. Mr. Zakem testifies that in the contested settlement agreement, Consumers fails to address the impacts the PCA will have on resource adequacy and the competitive market. Mr. Zakem explains that the settlement agreement does not require that the 500 ZRC capacity need that Consumers is seeking to fill through the one-time solicitation agreed to under subsection 6.b.i of the settlement agreement "be

additional to what is already being counted toward MISO Zone 7's resource adequacy requirements." 10 Tr 4297. Mr. Zakem opines that because the settlement agreement does not require that the capacity being added by Consumers be additional to that already available in Zone 7, the settlement agreement is subject to concerns about "insufficient resources in the zone for a competitive pricing market." 10 Tr 4298. Mr. Zakem therefore recommends the Commission "examine the [s]ettlement [agreement] carefully and review its effects on resource adequacy and competitive pricing in Zone 7" and if the Commission finds that the settlement agreement "fails to adequately address resource adequacy or anti-competitive concerns, then the Commission should reject the [s]ettlement [agreement]." 10 Tr 4298.

4. The Commission Staff

In the Staff's direct testimony, Paul Proudfoot, the Director of the Energy Resources Division, asserts that Consumers' PCA, as modified by the settlement agreement, meets the statutory requirements of Section 6t(8) of Act 341, MCL 460.6t(8). 10 Tr 4400. For this reason, Mr. Proudfoot recommends the Commission approve the contested settlement agreement in its entirety without recommending changes under Section 6t(7). 10 Tr 4400. Mr. Proudfoot also states that the contested settlement agreement meets the requirements of Rule 431. 10 Tr 4400.

5. Biomass Merchant Plants

The BMPs presented the direct testimony of Richard A. Polich, a Managing Director with GDS Associates, Inc. Mr. Polich testifies that the continued operation of the biomass plants can offset some deficiencies he posits are present in the proposed contested settlement agreement.

Mr. Polich opines that the settlement inconsistently results in Consumers having excess generation capacity in some years and capacity shortages in other years, which he argues is contrary to IRP best practices. Mr. Polich explains:

> The settlement [agreement] includes procurement of the Covert Generation Facility (Covert) in 2023 which results in Consumers' having 20.1% excess capacity. It then adds 700 MW (ZRC) of generation resources in 2025 that is procured through a competitive solicitation that is deeply flawed. Although Consumers retires 1,344 MW (ZRC) of generation in 2025, the [s]ettlement [agreement] would result in 16.2% excess generation in 2025 and an average of 18.7% excess generation over the next six years, assuming solar generation continues to be accredited at 50% of real capacity by MISO.

10 Tr 4277. Further, Mr. Polich adds that "[t]he addition of Covert in 2023 means Consumers' rate payers will be paying 2 years of unnecessary costs for Covert capacity that is unnecessary." 10 Tr 4277. Mr. Polich likens the biomass plants to solar generation as they are net zero carbon generation and to natural gas plants as they are baseload generation. Mr. Polich concludes that:

> If it is reasonable and prudent for Consumers to acquire both fossil and renewable capacity from 2023 through 2030 that results in excess capacity for the period of 2023-2030, the prudent course of action is for Consumers to continue to purchase capacity and energy from the Biomass Plants after the expiration of their current contracts through at least 2035 when Consumers is likely to be capacity deficient.

10 Tr 4278.

Mr. Polich argues that the one-time solicitation outlined in section 6 of the settlement agreement is "deeply flawed." 10 Tr 4278. Mr. Polich posits that the timing of the competitive solicitation is flawed as "Consumers is proposing to start the procurement process so the capacity of both tranches will provide capacity in 2025." 10 Tr 4278. Mr. Polich opines that:

> The timing of the procurement process will not result in new capacity being added to the Michigan market and will likely favor existing generation facilities such as the Kalamazoo Plant, Livingston Plant and Dearborn Industrial Generation because it will be impossible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing and construct the plant by 2025.

10 Tr 4279. Mr. Polich concludes that, given the timeline to obtain a MISO interconnection agreement, complete project engineering, and obtain financing, "it is very unlikely that there will be sufficient time to complete a power generation project for operation in 2025." 10 Tr 4279.

Mr. Polich also argues that "MISO Zone 7 is projected to be short 397.4 MW (ZRC) in 2023." 10 Tr 4279. Mr. Polich notes that "MISO's recent [sic] completed 2022/2023 Planning Resource Auction (PRA) resulted in capacity shortages in all northern MISO regions due to planned retirements of fossil generation resources . . . . The PRA resulted in capacity costs of $236.66/MW-day in MISO Zone 7, which is equal to the cost of new entry [CONE] or cost of adding new gas fired generation." 10 Tr 4279. Mr. Polich posits that this "shows the volatility of the MISO planning process to which Consumers and its customers will be subject." 10 Tr 4279.

Mr. Polich posits that the one-time solicitation outlined in the settlement agreement "results in a preference for non-intermittent fossil generation . . ." 10 Tr 4280. As outlined in the settlement agreement, the one-time solicitation seeks projects that will provide the company with capacity in MISO Zone 7 starting in the 2025 planning year. The settlement agreement also states that the first tranche will seek "dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7." Settlement Agreement, p. 6. Mr. Polich argues that these requirements preclude the participation of the BMPs as they will still be under contract in 2025 and can be dispatched on 24 hours-notice, as opposed to hourly. 10 Tr 4280. Mr. Polich further asserts that "only generation resources which are currently operating, not under contract with Consumers, have obtained MISO interconnection approval, and completed primary engineering are likely to be able to bid into the One-Time Solicitation." 10 Tr 4280.

Mr. Polich takes issue with the language in the settlement agreement describing the second tranche of the one-time solicitation that states, "[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources." 10 Tr 4280 (quoting Settlement

Agreement, p. 6). Mr. Polich posits that "[t]he term 'clean capacity resources' is an undefined term and can mean any generation resource that is cleaner that [sic] Consumers existing generation resources. Thus, natural gas plants could offer proposals into the second tranche because the language is very ambiguous." 10 Tr 4280.

Mr. Polich opines that "the One-Time Solicitation will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity." 10 Tr 4281. Mr. Polich argues that an increase in the average price of natural gas over the last two years "clearly demonstrates the volatility of natural gas pricing and highlights the risk of becoming totally dependent on such a single, volatile fuel source." 10 Tr 4281.

Mr. Polich also posits that the one-time solicitation in the second tranche of the settlement agreement "will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials[,]" specifically lithium carbonate. 10 Tr 4281.

Mr. Polich opines that if MISO changes the solar ZRC accreditation from its current 50% accreditation to a 30% accreditation, Consumers will face a capacity shortfall in 2031 due to closing of Karn Units 3 and 4 and the expiration of Consumers contract with Midland Cogeneration Venture. 10 Tr 4282.

Mr. Polich avers that the settlement agreement does not meet the stated goals of paragraph 16 "to be Carbon Neutral by 2040[,]" as the Covert plant and 200 MW of generation from PPAs originating under the one-time solicitation "are fossil fuel generation resources and are not carbon neutral." 10 Tr 4283.

In conclusion, Mr. Polich requests, on behalf of the BMPs that "the Commission approve the Settlement Agreement only if it is amended to include a provision whereby Consumers Energy continues to purchase capacity and energy from the Biomass Plants" through amended PPAs. 10 Tr 4286.

6. Wolverine Power Supply Cooperative

WPSC presented the direct testimony of Thomas King, Jr. Mr. King argues that "Consumers Energy's and Michigan's reliability and resource adequacy situation is no better (and arguably, worse) under the proposed Settlement Agreement than in the originally filed IRP." 10 Tr 4301. Mr. King posits that "the changes reflected in the proposed Settlement Agreement continue to assume capacity replacements that add no incremental capacity to MISO Zone 7." 10 Tr 4302. Mr. King provides MISO's 2022 PRA results as exhibit WPSC-6. Mr. King argues that this exhibit demonstrates why MISO's North and Central Zones cleared at CONE in 2022. Mr. King quotes MISO as stating "that previous projections of surplus were 'eroded by an increased load forecast, less capacity entering the auction as result of retirements, and the decreased accredited capacity of new resources.'" 10 Tr 4303 (quoting Exhibit WPSC-6, slide 2)(emphasis omitted). Mr. King posits that "[w]hen load growth is under-forecasted, dispatchable resources are retired too quickly, and intermittent resources are over-accredited, reliability is at risk." 10 Tr 4303. Mr. King further quotes the MISO 2022 PRA results as stating that "[u]nless more capacity is built that can supply reliable generation, shortfalls such as those highlighted in this year's auction will continue." 10 Tr 4303 (quoting Exhibit WPSC-6, slide 9).

Mr. King further avers that under the settlement agreement, Consumers' plan is "based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources that

likely cannot be built in time and, therefore, is likely to result in the purchase from the affiliated plants because they will be the only dispatchable resources in Zone 7 . . . .” 10 Tr 4302-4303.

Finally, Mr. King argues that “when Consumers’ PCA and proposed Settlement Agreement assumptions are updated to reflect more current data from Consumers’ own capacity demonstration filing in Case No. U-21099 and more reasonable assumptions, Consumers will likely be capacity negative in 2025[,]” meaning it will be “unlikely to serve its own load with its own resources in 2025.” 10 Tr 4303-4304. Mr. King posits that the assumptions Consumers used in its capacity demonstration are unreasonable. Specifically, Mr. King states that it is unreasonable for Consumers to assume a declining PRMR in its PCA and capacity demonstration as “it conflicts with MISO’s statements of increasing load forecasts (see Exhibit WPSC-6), Wolverine’s own growth, and publicly disclosed growth in Michigan.” 10 Tr 4305. Similar to the BMPs, Mr. King avers that “MISO is considering changes to solar capacity accreditation to move from a static solar accreditation value to an Effective Load Carrying Capability (ELCC) approach, similar to what is used for wind.” 10 Tr 4306-4307. Mr. King also outlines similar concerns regarding supply chain challenges causing disruptions to solar project developments. Specifically, Mr. King opines that “disruptions in the solar industry due to the United States Department of Commerce [DOC] investigation into Chinese solar tariff avoidance, are likely to result in project development delays.” 10 Tr 4307.

Mr. King concludes that the Commission “should reject this settlement [agreement]” and “adjust the timeline for retirement of Campbell 3 in a way that reasonably ensures replacement is possible—not only for the joint owners of Campbell 3, but for all LSEs [load serving entities] who rely on the grid to ensure their own reliability . . . .” 10 Tr 4309.

B. Rebuttal Testimony

1. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

Mr. Jester, on behalf of MNS and CUB, responds to the direct settlement testimony of WPSC, Energy Michigan, and the BMPs. Mr. Jester focused his rebuttal testimony on "the objecting parties' claims regarding resource adequacy, the procurement of new clean energy resources by 2025, and MISO capacity credit for solar resources." 10 Tr 4346.

Mr. Jester responds to claims by WPSC and Energy Michigan that the settlement agreement would worsen the resource adequacy measures in Zone 7 by arguing that "[u]nder the settlement, more than 2,000 ZRCs of capacity will be added to Zone 7 over the next several years." 10 Tr 4349. Mr. Jester posits that "[t]hese resource additions will not only provide replacement capacity for the retiring Campbell coal plant in 2025, they will result in a significant net increase of capacity when compared to the status quo." 10 Tr 4349. Specifically, Mr. Jester provides that "the settlement [agreement] will add 1,114 ZRCs to MISO Zone 7 through the acquisition of the Covert combined-cycle gas plant in 2023." 10 Tr 4349 (footnote omitted). Mr. Jester adds that "the settlement [agreement] provides that Consumers will deploy a new, utility-scale battery storage program in the years 2024-27, which will add approximately 71 ZRCs of new capacity." 10 Tr 4349-4350 (footnote omitted). Mr. Jester posits that "because the settlement agreement preserves the solar ramp-up proposed as part of the original PCA, the settlement [agreement] would add 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029 with further increases throughout the 2030s." 10 Tr 4350 (footnote omitted). Finally, Mr. Jester argues that "by preserving the EWR and DR provisions from Consumers' original PCA, the settlement [agreement] will provide 94 ZRCs of demand-side resources by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years."

10 Tr 4350 (footnote omitted). Mr. Jester concludes that these resource additions will support resource adequacy by providing replacement capacity for the retiring Campbell Units in May 2025. Specifically, Mr. Jester avers that "[i]n the 2025/2026 planning year . . . the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected increase will be at least 923 ZRCs." 10 Tr 4350. Mr. Jester notes that these calculations are conservative as they only account for the first tranche of the one-time solicitation seeking up 500 ZRCs of energy and capacity for up to 10 years from dispatchable generation and do not include the resources from the second tranche seeking up to 200 ZRCs of energy and capacity for up to 25 years from clean capacity resources. Mr. Jester posits that the calculations also assume that all of the dispatchable ZRCs come from existing generation sources. Mr. Jester concludes that "the settlement [agreement] will bolster Zone 7's resource adequacy" and as such, the Commission should disregard resource adequacy concerns raised by WPSC and Energy Michigan. 10 Tr 4352.

Mr. Jester responds to claims by WPSC and posits that "the settlement agreement will improve Consumers' capacity position relative to the original IRP." 10 Tr 4352. Mr. Jester opines that WPSC's claim that the proposed settlement agreement continues to assume capacity replacements that add no incremental capacity to Zone 7 is "plainly incorrect" as "the settlement provides for more than 2,000 ZRCs of new Zone 7 capacity over the next six years, including the addition of the Covert plant (1,114 ZRC) in 2023. 10 Tr 4353. Mr. Jester posits that, as explained above, the one-time solicitation will result in a net increase of ZRCs in both the 2025/26 and 2028/29 planning years. 10 Tr 4353.

Mr. Jester responds to WPSC's arguments that solicited resources cannot be built in time to provide energy and capacity in the 2025/26 planning year. Mr. Jester posits that "no party has claimed that the dispatchable generation tranche will be supplied with new resources" and thus,

"the evidence does not support Mr. King's speculative claims about the difficulty of developing new clean energy resources by 2025/26." 10 Tr 4353. Further, Mr. Jester avers that "Consumers would have enough capacity resources to meet customer needs in 2025/26 even if the one-time solicitation failed entirely." 10 Tr 4353.

Finally, regarding Consumers' capacity position, Mr. Jester rebuts WPSC's claim that Consumers will be capacity negative in 2025. Mr. Jester posits that the testimony provided by Mr. King "does not explain some of the assumptions reflected in [Exhibit WPSC-7]" and "does not present independent sources to support his claims about increased load and the PRMR margin." 10 Tr 4355 (footnote omitted). Mr. Jester also avers that Mr. King's projected capacity position assumes that Karn Units 3 and 4 were operating in planning year 2025/2026 when Consumers capacity demonstration filing assumed Karn Units 3 and 4 would have retired in 2023, and the CMS plants would be acquired in 2025, in line with the implementation of the original PCA. Mr. Jester notes that in Case No. U-21099, the Staff concluded that "all Michigan LSEs have satisfied the capacity demonstration requirements and have procured appropriate levels of resources for planning year 2025/26." 10 Tr 4356 (quoting Case No. U-21099, filing #U-21099-0060, p. iii).

Mr. Jester addresses the arguments of the BMPs and WPSC about recent PRA results. As Mr. Jester summarizes, "Mr. Polich asserts that MISO Zone 7 is projected to be short in 2023, and Mr. King cites the PRA results in warning more broadly about reliability risks." 10 Tr 4358 (footnote omitted). Mr. Jester opines that "[a]lthough . . . MISO should carefully scrutinize the PRA results and pursue solutions to improve resource adequacy for MISO North/Central, the auction results do not undercut the settlement agreement in this case." 10 Tr 4358. Mr. Jester reiterates that "the settlement agreement will *improve* Zone 7's resource adequacy." 10 Tr 4358-

4359 (emphasis in original). Further, Mr. Jester posits that "[b]ecause the settlement improves the capacity position of MISO Zone 7, it therefore also improves the capacity position of MISO's North/Central region." 10 Tr 4360.

Mr. Jester responds to the BMPs' and WPSC's concerns that there is not enough time to develop new resources capable of bidding into the one-time solicitation for clean energy resources and the possible decline of the ELCC of solar. Mr. Jester posits that concerns about developing clean energy resources by the 2025/2026 planning year are based on the assumption that the development process would not start until 2023. 10 Tr 4361. Mr. Jester first reiterates his position that "no one has suggested that the dispatchable generation tranche (500 ZRCs) of the one-time solicitation will be filled with new resources. . . ." 10 Tr 4362. Mr. Jester then opines that while the witnesses for the BMPs and WPSC assume that projects will not begin development until 2023, "[i]n reality, there are numerous clean energy projects already in the MISO generator interconnection queue. Because these projects are already in development, many of them will likely be capable of bidding into the solicitations for planning year 2025/26." 10 Tr 4362-4363. Mr. Jester posits that there are currently "more than 13,011 MW of solar, battery, and solar/battery hybrid projects located in the MISO Zone 7 that have an application in-service date by or before June 1, 2025" including "9,842 MW of solar, 1,249 MW of solar/battery hybrid, and 1,920 MW of battery storage." 10 Tr 4363-4364 (footnotes omitted). Mr. Jester notes that a number of the projects have completed phase 2 or phase 3 of interconnection studies and are therefore highly likely to proceed. 10 Tr 4364. Mr. Jester thus concludes that the concerns raised by the BMPs and WPSC are misplaced.

Regarding the concerns of the BMPs and WPSC about the potential decline of solar ELCC from 50%, Mr. Jester posits that "[a]lthough MISO has had discussions about adjusting solar's

ELCC as part of its future shift to a seasonal capacity market, no such proposal has been finalized nor submitted for FERC [Federal Energy Regulatory Commission] approval." 10 Tr 4365. Mr. Jester notes that a MISO stakeholder process subcommittee has been using modeling assumptions including an "ELCC of 50% through 2026, and with the ELCC linearly declining in subsequent years until it hits 20% in 2041." 10 Tr 4365-4366 (footnote omitted). In his footnote, Mr. Jester elaborates that "[f]or the previous year's analysis, the subcommittee modeled a decline to 30%, which may be where Mr. Polich got his figure." 10 Tr 4366, n. 51. However, Mr. Jester opines that "[t]his modeling document does not undercut the reasonableness of the settlement agreement[,]" providing that "this document is simply describing a modeling analysis; it does not reflect a policy change." 10 Tr 4366. Mr. Jester also provides that "accreditation for each solar facility begins at 50% until operational records from that facility become available, after which it is based on average production during the hours of 2pm to 5pm ET in the months of June, July, and August." 10 Tr 4366 (footnote omitted). Mr. Jester argues that this distinction is important as "there is on-the-ground evidence in Michigan that the ELCC for solar facilities may be much higher." 10 Tr 4367. Specifically, "Consumers currently has three solar facilities whose MISO capacity credit ranges between 56.67% and 67%." 10 Tr 4367 (footnote omitted). Finally, Mr. Jester notes that "although the ELCC of new solar may decline if solar achieves high levels of penetration in Michigan, that effect can be mitigated, and this dynamic will not affect the capacity provided by solar deployed in the earlier years of Consumers' resource plan." 10 Tr 4367.

2. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

Kevin Lucas, Senior Director of Utility Regulation and Policy at the Solar Energy Industries Association (SEIA), responds to the direct settlement testimony of WPSC on behalf of the CEOs. Mr. Lucas responds to the assertion by WPSC's witness, Mr. King, that the solar capacity sought

by Consumers "will not be available by 2025 due to the current United States Department of Commerce . . . investigation regarding avoidance of tariffs from Chinese-made solar cells." 10 Tr 4382. Mr. Lucas provides that "the DOC is investigating whether solar imports from Cambodia, Malaysia, Thailand, and Vietnam are circumventing antidumping and countervailing duties on Chinese-made crystalline silicon cells" and further, "[i]f imposed, tariffs would increase the cost of solar products from these countries 50-250% . . . ." 10 Tr 4382. Mr. Lucas avers that "[b]ecause of the uncertainty surrounding pricing of solar panels due to the retroactive nature of potential tariffs, panel shipments to the US have largely frozen since DOC initiated its investigation. This in turn impacts projects that are under construction and planned to come online in the near future as they are unable to secure a supply of solar panels." 10 Tr 4383. However, Mr. Lucas posits that "SEIA believes the current supply chain issue is largely short-term and that it will be mitigated when a decision is reached and as domestic manufacturing capacity comes online." 10 Tr 4384. Thus, Mr. Lucas concludes that Mr. King's arguments are not supported by analysis and "[w]hile there may be some projects in Michigan that experience schedule impacts from the DOC investigation, these impacts are concentrated in the relatively near-term period." 10 Tr 4384.

3. The Commission Staff

Mr. Proudfoot, on behalf of the Staff, responds to the direct settlement testimony of Energy Michigan and WPSC. Mr. Proudfoot limits his rebuttal testimony to the issues of the resource acquisition methodology of the one-time solicitation, resource adequacy, and the application of the settlement agreement factors outlined in Rule 431(5) parts (b) and (c). Addressing Mr. Zakem's concerns that the settlement agreement does not require that the 500 ZRCs acquired through the one-time solicitation be additional resources to those present in Zone 7, Mr. Proudfoot posits that

"Mr. Zakem fails to recognize that Subsection 6.b.1. does not require the 500 ZRCs to be pre-existing (already counted towards MISO Zone 7 resource adequacy)." 10 Tr 4404. Mr. Proudfoot notes that under the terms of the settlement agreement, these resources will be competitively bid, thus "respondents to the solicitation could be from some of the projects currently in the MISO Queue (ITC Transmission, Michigan only) that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3." 10 Tr 4404 (footnote omitted).

Mr. Proudfoot states that, in contrast to the RFP conducted by the company in its IRP filing which was limited to pre-existing gas resources within Zone 7, "the Company is now requesting dispatchable, non-intermittent resources (not specifically gas) with no requirement to be pre-existing." 10 Tr 4404. Mr. Proudfoot argues that "between existing projects and the intermittent and dispatchable projects in the MISO Queue, there is opportunity to add new capacity within MISO Zone 7." 10 Tr 4404. Mr. Proudfoot also notes that in the second tranche of the one-time solicitation provided for in subsection 6.b.1.ii of the settlement agreement, "the Company will request 200 ZRCs from unaffiliated third parties via Power Purchase Agreements (PPAs) for intermittent and dispatchable resources." 10 Tr 4405. Thus, Mr. Proudfoot concludes that "[b]etween the two tranches, the Settlement Agreement provides the opportunity for a wide variety of new resources to bid in and ultimately be built within MISO Zone 7 . . . ." 10 Tr 4405.

Mr. Proudfoot responds to resource adequacy concerns made by Energy Michigan and WPSC. Mr. Proudfoot asserts that the settlement agreement is "a resource adequacy improvement over the Company's original PCA." 10 Tr 4405. Mr. Proudfoot cites the key difference between the resource adequacy of the company's original PCA and the settlement agreement to be the delayed retirement of Karn Units 3 and 4. Mr. Proudfoot explains that the original PCA called for the retirement of Karn Units 3 and 4 by May 31, 2023, while the settlement agreement delays the

retirement until May 31, 2031. Mr. Proudfoot posits that Consumers "was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7" while the settlement agreement "only retires a portion of that amount, approximately 1500 MW . . . ." 10 Tr 4405. Further, Mr. Proudfoot notes that along with the commitment to retire the entire Campbell plant, Consumers "is proposing to add approximately 1176 MW to Zone 7 through the acquisition of the Covert Power Plant." 10 Tr 4405. Further, Mr. Proudfoot provides that Consumers "continues its solar build out and is expected to add 300 MW of solar resources in 2023, 500 MW of solar resources in 2024, and 500 MW of solar resources in 2025[,]" noting that under the current MISO ELCC construct, "that is approximately 400 ZRC's [sic] of new resources within MISO Zone 7." 10 Tr 4406 (footnote omitted). Mr. Proudfoot adds that the one-time solicitation for 700 MW set forth in the settlement agreement is additional to the resources outlined above. 10 Tr 4406. Mr. Proudfoot concludes that the "Staff does not believe the [settlement agreement] is likely to result in the Company being short on capacity in 2025." 10 Tr 4406. Mr. Proudfoot opines that the 7.4% reserve margin used by Consumers in its Capacity Demonstration in Case No. U-21099 is reasonable as it "comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report." 10 Tr 4406 (footnote omitted).

Regarding Rule 431(5)(a), Mr. Proudfoot testifies that all parties have been given an opportunity to present arguments in opposition to the settlement agreement through direct and rebuttal testimony. 10 Tr 4407. In regard to Rule 431(5)(b) and (c), Mr. Proudfoot asserts that the "Staff believes that Consumers has adequately met its requirements under [Public Act] 341 of 2016 . . . and provided a reasonable revised PCA." 10 Tr 4407. Mr. Proudfoot posits that not only did Consumers and the Staff sign the settlement agreement, but so did other parties who represent residential customers (the Attorney General, CUB, and Urban Core Collective); commercial and

industrial customers (HSC, MCV, and MPPA); businesses in Michigan's advanced energy sector (EIBC/IEI/CGA); environmental groups (MNS and the CEOs); a transmission company (METC); and third-party developers (GLREA). 10 Tr 4407-4408. Mr. Proudfoot opines that the signatories to the settlement agreement "represent most, if not all, of Michigan's sectors concerned with the future of energy related issues." 10 Tr 4408. Mr. Proudfoot concludes that "it is Staff's opinion that this [settlement agreement] meets the requirements of Rule 431." 10 Tr 4408.

4. Biomass Merchant Plants

Mr. Polich, on behalf of the BMPs, filed rebuttal testimony to reassert his position that the continued operation of the biomass plants fosters resource adequacy and contributes to Consumers goal of being carbon neutral by 2040. 10 Tr 4289. Mr. Polich takes the position that "it is in the Public Interest for the continued utilization of the Biomass Plants to be incorporated into the [s]ettlement [agreement] by extending their contracts through at least 2035" as it will "help alleviate Consumers' capacity deficiency that occurs in several years of 2025 through 2038 . . . ." 10 Tr 4289. Mr. Polich poses that there are "significant risks associated with adding 7,800 MW of solar capacity as proposed[,]" including the magnitude of the capacity; the possible lowering of MISO's current 50% solar accreditation; and MISO interconnection, development, financing, and construction risks. 10 Tr 4290-4291. Mr. Polich also notes the settlement agreement's "reliance on natural gas generation as the only form of non-intermittent generation to supplement the renewable generation." 10 Tr 4291.

Mr. Polich responds to MNS' position that the settlement agreement improves upon Consumers' initially filed PCA by eliminating the purchase of certain gas plants from Consumers' affiliate CMS Enterprises. Mr. Polich asserts that "[s]ince the only bidders in the One-Time Solicitation first tranche will likely be existing generation, the bidders will be the same entities that

bid into Consumers' solicitation that resulted in three CMS plants being successful bidders." 10 Tr 4292. Mr. Polich also responds to Mr. Jester's testimony that the second tranche of the one-time solicitation is beneficial to the public interest. Mr. Polich argues that "the timing of the solicitation and 2025 in-service date will limit bidders to those with MISO interconnection agreements, preliminary engineering, major equipment under contract, and rights to construction sites already procured" adding that "it is highly unlikely any generation project can be constructed by the summer of 2025 in-service date." 10 Tr 4293.

5. Wolverine Power Supply Cooperative

Mr. King, on behalf of WPSC, responds to the direct testimony of MNS and the BMPs. Mr. King focuses his testimony on Mr. Jester's claims regarding "the clear reliability deficiencies resulting from the proposed: (1) one-time solicitation; (2) retirement dates for Campbell Unit 3 and Karn Units 3 and 4; and (3) transmission considerations." 10 Tr 4311. Additionally, Mr. King focuses on Mr. Polich's "statements identifying Zone 7 and Consumers as import dependent." 10 Tr 4311.

Mr. King disagrees with Mr. Jester's position that "the one-time solicitation of 700 ZRCs contemplated in the disputed [settlement] agreement is a reasonable and beneficial settlement [agreement] term sufficient to replace the retirement of Campbell Unit 3." 10 Tr 4311. Mr. King reasserts that "500 of the 700 ZRC[s] are unlikely to result in any new capacity to Zone 7 due to the solicitation requirements being 'dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year…[in] Zone 7.'" 10 Tr 4312 (quoting Settlement Agreement, p. 6). Mr. King further provides that "only the CMS plants, or a portion thereof, are available today in Zone 7. And nothing new exists in MISO's interconnection queue." 10 Tr 4312. Mr. King posits that, "the second tranche of 200 ZRCs are likely to be procured from

intermittent resources . . . because much like Tranche 1, there are unlikely any nonintermittent resources available today or in the MISO interconnection queue." 10 Tr 4312. Mr. King asserts that there are reliability implications if the CMS plants are the only resources available to participate in the one-time solicitation. Specifically, "[r]eplacing Campbell Unit 3 with existing Zone 7 capacity produces a net negative capacity position in the Zone." 10 Tr 4312.

Mr. King opines that by supporting the retirement of Campbell Unit 3, Mr. Jester, "fails to analyze, or even consider, the public health and safety impacts resulting from lower reliability." 10 Tr 4313.

Mr. King addresses Mr. Jester's position that delaying the retirement of Karn Units 3 and 4 from 2023 to 2031 is a reasonable and beneficial settlement term. Mr. King argues that "[w]hile the continued operation of existing resources is prudent in order to maintain reliability, extending the retirement date for Karn Units 3 and 4 does not appear to be a reasonable or prudent path as the units are, [sic] less reliable and provide insufficient additional capacity." 10 Tr 4314. Specifically, Mr. King provides that the settlement agreement proposes to extend the operation Karn Units 3 and 4 which have an installed capacity of 1,120 MW and accredited capacity of 790 MW (70.5% accredited) while continuing to expedite the retirement of the Campbell Units which have an installed capacity of 1,393 MW and an accredited capacity of 1,346 MW (96.6% accredited). 10 Tr 4314.

Mr. King refutes Mr. Jester's testimony supporting the settlement terms that require Consumers to consider the reliability and economic value of transmission in its next IRP to access resources outside Zone 7. Mr. King posits that this consideration must happen sooner than Consumers' next IRP as "Zone 7 is already import reliant in the upcoming 2022/23 Planning Year (and has been for seven of the last nine capacity auctions) to meet its PRMR . . . ." 10 Tr 4314.

Mr. King avers that "[w]hen Consumers and Zone 7 are import reliant . . . [i]f one of a few existing ties fails or export capability (elsewhere) is reduced (e.g., retirements or forced outage), proportional load shed is the next step." 10 Tr 4315.

Finally, Mr. King encourages improving access to external resources. 10 Tr 4315. Mr. King posits that "Michigan should demand greater, more resilient, and more diverse ties to the greater market/grid." 10 Tr 4315.

6. Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance

EIBC/IEI/CGA presented the rebuttal testimony of Edward Burgess, the Senior Director at Strategen Consulting. Mr. Burgess responds to the direct testimony of Mr. Polich on behalf of the BMPs on "timing delays and other risks associated with solar development[,]" specifically, that the settlement "simply ignores risks associated with intermittent solar generation." 10 Tr 4388-4389 (footnote omitted). Mr. Burgess opines that the settlement addresses some of these potential risks by turning them into opportunities, such as better utilization of Michigan manufactured components and low-carbon manufacturing. 10 Tr 4389. Mr. Burgess rebuts Mr. Polich's position that the one-time solicitation outlined in the settlement agreement is flawed. Mr. Burgess posits that Mr. Polich's assumptions that "the second tranche procurement Settlement Paragraph 6.b.ii 'will likely result in the acquisition of only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of material'" is an improper reading of the settlement [agreement]. 10 Tr 4389-4390 (quoting 10 Tr 4281) (footnote omitted). Mr. Burgess asserts that "[t]he fact that the 'duration of the contract length' will be taken into account for all new supply side resources, including solar and battery storage capacity options, will enable especially battery storage capacity options to be evaluated on par with intermittent resources in terms of the full price

of the contract." 10 Tr 4390 (quoting Settlement Agreement, p. 6). Further, Mr. Burgess adds that "the fact that the solicitation is tailored towards ZRCs that meet the Local Clearing Requirements of MISO Zone 7 means that it already inherently accounts for any intermittency concerns through the MISO capacity accreditation process." 10 Tr 4390.

Finally, Mr. Burgess posits that the technology neutral language of the one-time solicitation in section 6.b.ii of the settlement agreement rectifies concerns that Consumers' initial PCA "did not adequately model nor otherwise address the potential inclusion of battery storage resources." 10 Tr 4391.

7. Consumers

Consumers presented the rebuttal testimony and exhibits of Richard T. Blumenstock, Thomas P. Clark, and Michael A. Torrey. Each witness' testimony will be addressed here in turn. Mr. Blumenstock, Executive Director of Electric Supply at Consumers, focuses his rebuttal testimony on responding to assertions raised by Energy Michigan, WPSC, and the BMPs. Mr. Blumenstock provides an overview of how the settlement agreement aligns with subsection 6t(8)(a)(i-vii) of Act 341, MCL 460.6t(8)(a)(i-vii), on pages 7-15 of his rebuttal testimony. Mr. Blumenstock responds to the testimony of Energy Michigan's witness Zakem by claiming:

> Energy Michigan is continuing to rely on its direct testimony as previously submitted in this case before the Settlement Agreement was reached . . . . The problem with that approach is that Mr. Zakem's direct testimony was focused on the Company's purchase of the Dearborn Industrial Generation ("DIG"), the Kalamazoo River Generating Station ("Kalamazoo"), and the Livingston Generating Station ("Livingston") plants . . . and the Settlement Agreement no longer provides for the purchase of those plants in the manner initially proposed by the Company. Mr. Zakem has also made no adjustment to his initial position to account for the fact that the Settlement Agreement continues operation of Karn Units 3 and 4 until 2031, as opposed to 2023, as initially proposed by the Company.

10 Tr 4128-4129. Thus, Mr. Blumenstock posits that Mr. Zakem's assessment "no longer accurately describes the elements of the PCA, as modified by the Settlement Agreement."

10 Tr 4129. Mr. Blumenstock also claims that Mr. Zakem's position that the one-time solicitation provided for in the settlement agreement may result in resources that are already being counted toward resource adequacy requirements in MISO Zone 7 is speculative. 10 Tr 4129.

Mr. Blumenstock responds to WPSC's arguments on purported reliability issues that Mr. King claims are at risk in the settlement agreement. Addressing Mr. King's argument that Consumers will likely be capacity negative in 2025, Mr. Blumenstock argues that the 28 ZRC capacity shortfall Mr. King calculated is insignificant as "a small magnitude surplus *or* shortfall can shift over a relatively short period of time. This is why the Company implements a strategy of maintaining approximately 200 ZRCs of capacity surplus." 10 Tr 4131 (emphasis in original). Mr. Blumenstock posits that Mr. King's capacity position calculation is also flawed as it "relies on the exclusion of capacity acquired through the one-time solicitation . . ." 10 Tr 4131 (emphasis in original). Mr. Blumenstock further provides that Mr. King's "claim that the Company could be capacity negative in 2025 would assume the Company is wholly unsuccessful in its one-time solicitation—that 0 ZRC of capacity are acquired through a Request for Proposals soliciting up to 700 ZRCs." 10 Tr 4131. Mr. Blumenstock avers that Mr. King's testimony fails to explain how the equalization adjustment factor used in his capacity position is calculated or appropriately used. 10 Tr 4133.

Mr. Blumenstock responds to the BMPs' testimony by Mr. Polich that "the Company did not appropriately consider biomass plants in this IRP . . . ." 10 Tr 4135. Mr. Blumenstock opines that "the Company is not under any obligation to enter new PPAs with the BMPs or extend the BMPs' existing contracts." 10 Tr 4135. Mr. Blumenstock asserts that "the Company did consider biomass plants in the development of the IRP. The Company considered biomass plants as it began its modeling process, but due to the fact that those resources were not viable options on an

economic or cost basis, biomass plants did not pass the Company's resource screen process. 10 Tr 4136. Mr. Blumenstock notes that "the plants which make up the BMPs are included in the PCA through the end of their current PPA terms." 10 Tr 4136. Mr. Blumenstock opines that "the flaw in the BMPs' position is that the Company did not have adequate information to determine the cost of new PPAs or PPA extensions with the BMPs in the development of this IRP" and "throughout this proceeding, the BMPs have failed to produce any evidence in the record establishing the costs that the BMPs could agree to in new PPAs or PPA extension[s]." 10 Tr 4136.

Mr. Blumenstock addresses Mr. Polich's testimony making recommendations to the proposed settlement agreement, arguing that "Paragraph 22 of the Settlement Agreement provides that if the Commission rejects or modifies the Settlement Agreement or any provision of the Settlement Agreement, the Settlement Agreement shall be deemed to be withdrawn." 10 Tr 4137. Mr. Blumenstock also asserts that the BMPs' requested modifications to the settlement agreement are "beyond the scope of this contested settlement." 10 Tr 4138.

Mr. Blumenstock responds to Mr. Polich's claims that the settlement agreement will result in Consumers having "excess capacity between 2023 and 2030 and capacity shortages between 2031 and 2038." 10 Tr 4139. Mr. Blumenstock elaborates that "the Purchase Sale Agreement ('PSA') for [the Covert] plant provides for the purchase in 2023" and "Mr. Polich has also not established that the Company has any ability to move the start date of the Covert Plant purchase." 10 Tr 4140. Further, Mr. Blumenstock posits that "even if the Covert Plant does provide surplus energy and capacity for a short period, the Company can monetize the energy and capacity of the Covert Plant by selling it into the MISO markets and using the resulting revenue to lower power supply costs to

the benefit of customers." 10 Tr 4141. Responding to Mr. Polich's assertion that the one-time solicitation is not needed until 2030, Mr. Blumenstock opines that:

> the one-time solicitation included in the proposed Settlement Agreement also supports the retirement of Campbell Units 1, 2, and 3. It is expected that the 500 ZRCs of dispatchable generation and the 200 ZRCs of intermittent and non-intermittent clean resources will provide sufficiency of supply to support retirement of the Campbell Units. However, until such resources are acquired and operational on behalf of customers, the Settlement Agreement provides for continued operation of Karn Units 3 and 4, which provide low-cost capacity for the benefit of customers. The continued operation of Karn Units 3 and 4 further addresses reliability concerns for customers.

10 Tr 4141. Mr. Blumenstock concludes that "[b]ecause the one-time solicitation will support the retirement of Campbell Units 1, 2, and 3, and the need for continued operations of Karn 3 and 4 can be assessed in the future, the BMPs have not established that the one-time solicitation is unnecessary or to the detriment of customers." 10 Tr 4141-4142,

Mr. Blumenstock rebuts Mr. Polich's claim that the settlement agreement will result in a capacity shortfall position in the years 2031 through 2038. Mr. Blumenstock explains that "Mr. Polich suggests that *if* a change to solar accreditation is made at MISO, the PCA would result in capacity shortfalls eight years into the future." 10 Tr 4142 (emphasis in original). Mr. Blumenstock posits that "the PCA was developed using current MISO solar capacity accreditation practices." 10 Tr 4142. Mr. Blumenstock opines that "[w]hile discussions in MISO have raised the possibility of changes to solar capacity accreditation, it would be premature to adopt such changes ahead of MISO itself issuing the rule change." 10 Tr 4142. Further, Mr. Blumenstock provides that "at the Company's existing solar facilities, capacity accreditation, based on actual performance, has been as high as 65%" and "[w]hile the possibility of lowering the accreditation is under consideration, actual performance will ultimately dictate the levels of capacity customers receive from these resources." 10 Tr 4142. Additionally, Mr. Blumenstock

notes that Mr. Polich's projected capacity shortfall is to occur eight years in the future. Mr. Blumenstock avers that Consumers "will file at least one, if not multiple IRPs between now and that time. If changes to solar accreditation occur at MISO, the Company has ample time to respond and adjust the PCA." 10 Tr 4143-4144.

Mr. Blumenstock responds to Mr. Polich's arguments that the one-time solicitation proposed in the settlement agreement is "deeply flawed." 10 Tr 4144; 10 Tr 4289. In response to Mr. Polich's claims that "the one-time solicitation will favor existing generation facilities[,]" specifically due to "engineering, financing, and construction time limitations, as well as delays in the MISO interconnection process[,]" Mr. Blumenstock "disagrees that this is a flaw in the design of the solicitation." 10 Tr 4144. Mr. Blumenstock posits that "the resources acquired in the one-time solicitation will help replace the capacity and energy lost by Campbell Units 1, 2, and 3 in 2025" and "[f]urthermore, beyond speculating what plants can participate, Mr. Polich fails to establish anything unreasonable about the solicitation." 10 Tr 4144. Mr. Blumenstock avers that the resources sought in the one-time solicitation are consistent with the modeling presented by the company in its principal case.

In response to Mr. Polich's argument that Consumers chose to exclude the BMPs from its IRP, Mr. Blumenstock avers that the settlement provides that the first tranche of the solicitation requires "dispatchable, nonintermittent generation *capable* of dispatching up or down in every hour of the year in response to wholesale energy market signals." 10 Tr 4146 (emphasis in original) (quoting Settlement Agreement, p. 6); *see also*, 10 Tr 4272. Mr. Blumenstock argues that Mr. Polich has asserted throughout these proceedings "that the BMPs' 'generation facilities can provide *around the clock*, renewable*, dispatchable* and reliable power generation.'" 10 Tr 4146 (emphasis in original) (quoting 7 Tr 2684). Mr. Blumenstock concludes that Mr. Polich's testimony with regard

to the fact that the BMPs are dispatchable has been inconsistent. 10 Tr 4146. Additionally, Mr. Blumenstock provides that "certain BMPs are offered into the MISO Day-Ahead Market as units which can dispatch on an hourly basis. Since the MISO Day-Ahead Market clears the day prior to operation, the plants are provided dispatch notice prior to actual operation." 10 Tr 4147.

Mr. Blumenstock rebuts Mr. Polich's claim that the term "clean capacity resources," is not defined in the settlement agreement. Mr. Blumenstock asserts that "[t]he Company's generation portfolio includes fossil fuel and clean capacity resources such as solar and hydro generation." 10 Tr 4147. Mr. Blumenstock provides that "[t]he Settlement Agreement specifically provides that '[t]his tranche will seek intermittent resources and dispatchable, nonintermittent clean capacity resources *(including battery storage resources)* providing capacity which meets the Local Clearing Requirement of MISO Zone 7.'" 10 Tr 4148 (emphasis in original) (quoting Settlement Agreement, p. 6). Mr. Blumenstock argues that "[s]ince the Settlement Agreement provides 'battery storage resources' as an example of the 'dispatchable, nonintermittent clean capacity resources' that can participate in the second tranche, the Settlement Agreement is not 'very ambiguous,' as Mr. Polich claims." 10 Tr 4148 (citing 10 Tr 4280).

Mr. Blumenstock addresses Mr. Polich's arguments that the one-time solicitation "'will likely result in Consumers acquiring [a] substantial amount of natural gas capacity in addition to the Covert capacity'" and "'volatility of natural gas pricing.'" 10 Tr 4148 (quoting 10 Tr 4281). Mr. Blumenstock dismisses Mr. Polich's arguments as speculation and asserts that Consumers witness Brian D. Gallaway addressed gas prices in the initial record of this case and "established that gas price volatility is not expected to continue into the future." 10 Tr 4148. Further, Mr. Blumenstock asserts that "the Company will have an incredibly diverse resources portfolio that includes: pumped storage and hydro generation, gas generation, wind generation, solar

generation, energy efficiency, DR, and emerging technologies such as grid modernization and battery storage to meet the future demand of its customers." 10 Tr 4148-4149. Mr. Blumenstock also posits that "[t]he Company maintains PPAs with numerous technology types." 10 Tr 4149.

Mr. Blumenstock addresses Mr. Polich's final concern with the one-time solicitation, that the one-time solicitation will result in "'only intermittent generation because solar generation with battery storage will likely be too expensive to compete with solar generation without battery storage and due to shortages of materials.'" 10 Tr 4149 (quoting 10 Tr 4281). Mr. Blumenstock again dismisses this argument as speculation and opines that "[t]he one-time solicitation is a competitive bidding process which will consider the value of the resources which are bid. If certain resources are 'too expensive,' as Mr. Polich claims, that issue will naturally be resolved through the ranking of eligible bids." 10 Tr 4149.

Addressing Mr. Polich's testimony that the settlement agreement does not meet the intent of being carbon neutral by 2040 as stated in the settlement agreement, Mr. Blumenstock replies that "[p]aragraph 16 of the Settlement Agreement merely reiterates that the Company's filed IRP 'set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025.'" 10 Tr 4149 (quoting Settlement Agreement, p. 13). However, Mr. Blumenstock posits that "there is nothing in the Settlement Agreement that will necessarily impede the Company's ability to meet its goal." 10 Tr 4149. Further, Mr. Blumenstock provides that "the 20-year capacity plan provided by the Company in this IRP assumed cessation of the Covert Plant by May 31, 2040. The final solution in 2040 will vary dependent upon the evolution of cleaner technologies, the possibility of carbon sequestration technologies, and potential for carbon offsets." 10 Tr 4150.

Turning to Mr. Polich's assertion that Karn Units 3 and 4 could be designated as a system support resource (SSR) by MISO, Mr. Blumenstock posits that "[a]n SSR designation would not

be due to a capacity or energy shortfall. An SSR designation would result from an electric transmission system deficiency that must be mitigated before Karn Units 3 and 4 could be retired." 10 Tr 4152. Mr. Blumenstock avers that "Karn Units 3 and 4 will continue to operate to ensure near-term reliability for the benefit of Consumers Energy customers. These units may be operated through May 31, 2031, depending on the Company's capacity needs and the outcome of the Company's resource procurement efforts." 10 Tr 4152. Mr. Blumenstock also provides that the cost burden associated with designating Karn Units 3 and 4 as SSR units would shift to the entirety of Zone 7 and would thus not pose an increased risk to customers. 10 Tr 4152.

Mr. Blumenstock concludes that Energy Michigan, WPSC, and the BMPs have not established any basis for the Commission to reject the settlement agreement. 10 Tr 4154.

In his rebuttal testimony, Mr. Clark responds to claims raised by Energy Michigan, WPSC, and the BMPs. Specifically, Mr. Clark focuses his rebuttal testimony on: (1) reliability concerns raised by these witnesses in connection with Consumers' retirement of Campbell Unit 3; (2) the potential volatility of MISO's capacity planning process and its impact on the company's customers; (3) claims that the settlement agreement fails to address the forthcoming MISO seasonal capacity construct; (4) claims that the settlement agreement will impact reliability for residents in the lower peninsula and result in a capacity shortfall between 2031 and 2038; and (5) claims regarding competitive pricing in Michigan resulting from the settlement agreement. 10 Tr 4223.

Mr. Clark responds to Mr. King's positions on behalf of WPSC with regard to the company's projected solar capacity additions and their accreditations. Mr. Clark posits that the company is confident that its solar capacity expansion will be successful despite issues with supply chain and local zoning and "to the extent that the Company experiences minor delays beyond the 2025-2026

planning year, it continues to have sufficient capacity to reliably serve its load as a result of the continuing operation of Karn Units 3 and 4 and the one-time solicitation proposed in the Settlement Agreement." 10 Tr 4227. With respect to a potential reduction in solar capacity accreditation, Mr. Clark opines that "the current ELCC is 50% of a solar generator's installed capacity, and there is no certainty of timeline for a reduction from the current MISO practice." 10 Tr 4227.

Mr. Clark rebuts Mr. King's testimony "that a continued reduction to the Company's PRMR is not reasonable," stating that "[w]hile the Company's forecasted load may be increasing, the Company's internal waste reduction and demand response programs are also increasing, thereby offsetting a large portion of the growth." 10 Tr 4227. Mr. Clark adds that "the planning reserve margin ('PRM') provided by MISO is decreasing, thereby allowing the Company's PRMR to decrease rather than increase." 10 Tr 4227-4228 (footnote omitted). Mr. Clark provides that "[t]he Company's most recent capacity demonstration filing reflects that the PRM provided by MISO dropped from 8.70% for planning year 2022-2023 to 7.40% for planning year 2025-2026." 10 Tr 4228 (footnote omitted). Mr. Clark notes that "[t]he Planning Year 2022-2023 Loss of Load Expectation Study Report indicates that the 2025-2026 planning year PRM decreased slightly from the 2022-2023 planning year PRM primarily based upon expected new unit additions." 10 Tr 4228.

Addressing Mr. King's argument that Consumers' IRP is "based almost entirely on a 700 MW speculative solicitation of both dispatchable and intermittent resources[,]" Mr. Clark posits that "the Company has projected sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation." 10 Tr 4228 (quoting 10 Tr 4302-4303). Mr. Clark opines that "neither a short delay in the onboarding of this

additional capacity nor a lack of available additional economic capacity would have a material, detrimental impact to the Company's immediate capacity position[,]" which would be reviewed subsequently in later IRP filings. 10 Tr 4229.

Mr. Clark responds to Energy Michigan's testimony from Mr. Zakem that "the Settlement Agreement will impact resource adequacy and the competitive market because the 500 ZRCs of dispatchable capacity that the company is seeking via solicitation will not necessarily be in addition to what is already being counted toward LRZ 7's resource adequacy requirements." 10 Tr 4229. Mr. Clark argues that "Consumers Energy, like all other LSEs, is responsible for ensuring that it has adequate supply to meet its customers' needs." 10 Tr 4229. Mr. Clark posits that "the Company has a requirement to serve its own customers' load while meeting applicable MISO requirements. The Company does not have an obligation to ensure LRZ 7 has adequate capacity for all LSEs to meet their customers' supply needs." 10 Tr 4229.

Addressing Mr. Zakem's concerns that the settlement agreement is anti-competitive, Mr. Clark adds that:

> Other LSE's, [sic] like Energy Michigan's AES [alternative electric supplier] members maintain the obligation to serve their own load and to ensure equitable contribution to reliability requirements. Consumers Energy is not responsible to provide a reliability backstop for the benefit of AESs unless the requirement to provide backup capacity is triggered by an AES's failure to meet its own four-year forward capacity obligations as required under Public Act 341 of 2016.

10 Tr 4230. Mr. Clark avers that "[o]ther LSEs have been aware of the Company's PCA since June of 2021[,] which has provided ample time to secure resources they may need to satisfy their own capacity obligations." 10 Tr 4231. Further, Mr. Clark argues that "the Company has not issued the one-time solicitation yet and therefore, other LSEs continue to have the opportunity and ability to secure resources they may need to satisfy their own capacity obligations prior to the issuance of the one-time solicitation." *Id*. Mr. Clark posits that "[b]ased on Staff's March 25,

2022 Capacity Demonstration Results report[2] filed in Case No. U-21099, all LSEs met their filing requirement detailing how the necessary capacity resources will be met for the Planning Year 2025-2026 (with one exception)." *Id*. (footnote omitted). Mr. Clark opines that "since all LSEs provided capacity projections through Planning Year 2025-2026, the 500 ZRCs of capacity that the Company will solicit for starting in 2025 should have no impact on an LSE who should have already committed capacity for the Planning Year 2025-2026." 10 Tr 4231.

Mr. Clark then turns to the assertion of Mr. King on behalf of WPSC and Mr. Zakem on behalf of Energy Michigan on the impact the settlement agreement will have on resource adequacy. Mr. Clark avers that neither party provided specific information showing reliability risks to WPSC or Energy Michigan's members. 10 Tr 4233.

C. Initial Briefs

1. Energy Michigan

Energy Michigan contends that the Commission is required to determine that an electric utility's IRP "represents the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." Energy Michigan's initial brief, pp. 1-2 (quoting MCL 460.6t(8)(a)) (emphasis in original). Energy Michigan further posits that Rule 431 requires that for approval of a proposed contested settlement agreement, the Commission must find that "the settlement is in the public interest, represents a fair and reasonable resolution to the proceeding, and, if the settlement is contested, is supported by substantial evidence on the record as a whole." Energy Michigan's initial brief, p. 2 (quoting Rule 431(5)(c)). Energy Michigan avers that "[t]he Commission's administrative rules may not overrule the underlying statute." Energy Michigan's

[2] Consumers testimony references the Capacity Demonstration Results which can be accessed on the Commission's website at: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002Qy56AAC (accessed June 6, 2022).

initial brief, p. 2. Energy Michigan argues that "when a statute and an administrative rule conflict, the statute necessarily controls. While administrative agencies have what have been described as 'quasi-legislative' powers, such as rulemaking authority, these agencies cannot exercise legislative power by creating law or changing the laws enacted by the Legislature." *Id*. (quoting *Emagine Entertainment, Inc v Dep't of Treasury*, 334 Mich App 658, 664; 965 NW2d 720 (2020)). Energy Michigan posits that under this precedent, the Commission must consider whether the IRP appropriately balances the factors enumerated under Section 6t(8)(a) of Act 341, including: (1) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (2) reliability; and (3) competitive pricing. Energy Michigan's initial brief, pp. 2-3 (citing MCL 460.6t(8)(a)(i)(iii-iv)). Energy Michigan argues that "[b]ecause Consumers' proposed settlement [agreement] would have a detrimental effect on resource adequacy, reliability and competitive pricing in Michigan, the Commission should reject Consumers' proposed Settlement Agreement." Energy Michigan's initial brief, p. 3.

Energy Michigan asserts that the proposed settlement agreement fails to meet the standards set forth in Section 6t(8) of Act 341 and is not in the public interest. *Id*. Energy Michigan cites to the record to demonstrate that "the Company is proposing to solicit capacity from wholesale generators that may exist in LRZ 7." *Id*. (quoting 10 Tr 4229). Energy Michigan argues that changing ownership of resources that already exist in Zone 7 to meet Consumers' capacity needs "has adverse effects on resource adequacy, reliability, and competitive pricing." Energy Michigan's initial brief, p. 3. Energy Michigan argues that while Consumers "does not believe that it has any responsibility for the rest of Michigan (*i.e*., LRZ 7)[,]" the Commission "has a statutory responsibility to consider resource adequacy and reliability under the requirements of Section 6t." *Id*., pp. 3, 4.

Energy Michigan opines that if the one-time solicitation proposed in the settlement agreement is necessary, "the acquisition of 500 MW of existing in-zone capacity would not actually contribute to resource adequacy . . . ." *Id*., p. 4. Additionally, Energy Michigan posits that if Consumers does not need the capacity represented by the one-time solicitation, "that solicitation is not the most reasonable and prudent means of meeting the utility's capacity needs, as it would lead to an oversupply" and thus "has the potential to cause a market power issue." *Id*.

Finally, Energy Michigan "disputes the characterization of this settlement process as involving all parties or as being open to negotiation on the concerns that Energy Michigan expressed in its testimony and briefs." *Id*., p. 5. Energy Michigan claims that it "was never invited to a settlement meeting, and Energy Michigan's comments on the draft settlement agreement were neither welcomed nor considered, as [it was] explicitly told that no changes to the draft [it was] sent would be considered." *Id*.

Thus, Energy Michigan requests that the Commission reject the proposed settlement agreement as it would negatively affect resource adequacy, reliability, and competitive pricing in Michigan. *Id*.

2. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

MNS contends that the settlement agreement meets all of the requirements of Rule 431 and should be approved.

MNS asserts that the settlement agreement is in the public interest because it results in the closure of the Campbell plant and Consumers' exit from coal generation by 2025, and this step is critical to addressing the climate crisis and complying with the MI Healthy Climate Plan as shown in Mr. Jester and Mr. Gignac's testimony. MNS' initial brief, p. 4 (citing 10 Tr 4330, 4375). MNS asserts that the settlement agreement benefits the public health in other ways as well,

through the increase to solar resources, the avoidance of the construction of new gas plants, and the removal of numerous other air pollutants (in addition to carbon dioxide) which contribute to numerous premature deaths each year. MNS' initial brief, p. 5 (citing 7 Tr 2426).

MNS notes that the retirement of the Campbell plant provides cost benefits to ratepayers as well. MNS contends that the undisputed evidence in the case showed that Campbell Units 1 and 2 are uneconomic. With respect to Campbell Unit 3, responding to WPSC's argument that this closure should be delayed, MNS notes that the settlement agreement is not severable, making it impossible for the Commission to simply adjust that timeline but approve the settlement agreement. MNS argues that such a delay would be harmful to ratepayers because the retirement of Campbell in 2025 will save customers more than $150 million. MNS' initial brief, p. 8 (citing 10 Tr 4327).

MNS asserts that the settlement agreement is also in the public interest and a fair and reasonable resolution of the case because "it formalizes two important components of a cleaner grid: Consumers' solar ramp-up from its previous IRP; and faster deployment of battery storage investments . . . ." MNS' initial brief, pp. 8-9. MNS posits that Section 3 of the settlement agreement accelerates the transition to cleaner energy while reserving cost approval for later rate cases. MNS further indicates that the settlement agreement is in the public interest because it provides for stakeholder engagement prior to Consumers' first competitive solicitation for batteries (Section 3) and provides that the second tranche of the one-time ZRC solicitation will include battery storage resources (Section 6.b.ii.). Citing the testimony of Mr. Jester and Mr. Blumenstock, MNS contends that:

> Consumers' battery proposal is a fair and reasonable settlement term for three reasons: (1) it will 'bolster Consumers' maintenance of its PRMR'; (2) it will 'support resource adequacy in Zone 7'; and (3) it may 'lead to the development of new battery storage resources within Zone 7.' The addition of battery storage

> resources also addresses commodity price risks by providing 'flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment' and contributing to the diversification of Consumers' generation supply. Finally, because Consumers proposed to advance its battery storage investment in response to testimony from Commission Staff, MNS, and other parties, this settlement term reflects the input of parties who represent the public interest.

MNS' initial brief, p. 10 (quoting 10 Tr 4124, 4339).

MNS posits that the settlement agreement also benefits customers by removing the possibility of the CMS acquisitions which had affiliate transaction issues, significant costs, and significant operational risks. MNS points out that the settlement agreement also benefits ratepayers financially by providing for a 9% ROE to calculate the WACC for the Campbell regulatory asset (Section 5), which is more favorable than the 9.9% ROE approved in Case No. U-20963. MNS notes that Section 13 of the settlement agreement provides for the donations to low-income programs for the remaining term of the Campbell regulatory asset, and further provides that these funds will not be recovered from ratepayers. MNS' initial brief, pp. 12-15 (quoting 10 Tr 4336). Thus, MNS points out, the settlement agreement facilitates the retirement of aging coal units while providing for lower costs for ratepayers and the funding of low-income bill assistance programs. MNS' initial brief, p. 15.

MNS argues that the settlement agreement avoids the problematic aspects of Consumers' original PCA while retaining the benefits, noting that the settlement continues the ramp up of solar PPA procurement, retains the 50/50 ownership-to-PPA ratio, and retains the existing FCM calculation. MNS also points to provisions that benefit the communities that will be affected by the Campbell retirement including community engagement and transition plans (Section 7.b.). *Id*., pp. 16-19.

Responding to WPSC's arguments, MNS asserts that the settlement agreement will actually help improve resource adequacy. MNS notes that:

> the Settlement will add thousands of zonal resource credits (ZRCs) to Zone 7, including:
>
> • 1,114 ZRCs through the acquisition of the Covert combined-cycle gas plant;
> • a new battery storage program in the 2024-27, which will add 71 ZRCs of new capacity;
> • 250 ZRCs of new solar generation by the 2025/2026 planning year, increasing to 852 ZRCs by 2028/2029, with further increases throughout the 2030s; and
> • 94 ZRCs of demand-side resources (EWR and DR) by 2025/26, increasing to 231 ZRCs by 2028/29, with further increases in later years.

MNS' initial brief, p. 20 (citing 10 Tr 4347-4350; Settlement Agreement, paragraphs 1-3; Exhibit A-14, p. 9; and Exhibit MEC-79, p. 1). MNS highlights Mr. Jester's testimony that for the 2025/2026 planning year the settlement agreement will result in an estimated net increase of 127 ZRCs, and for the 2028/2029 planning year a net increase of 923 ZRCs. MNS' initial brief, p. 20 (citing 10 Tr 4349-4350). Added to this is Consumers' obligation to seek PPAs for up to 200 additional ZRCs (Section 6.b.ii.). MNS observes that the Staff agrees that resource adequacy will be strengthened, noting Mr. Proudfoot's testimony that Zone 7 resources will increase, under the terms of the settlement agreement, by approximately 400 ZRCs by 2025. MNS' initial brief, p. 22 (citing 10 Tr 4405-4406). MNS contends that the settlement agreement thereby complies with the statutory requirement that the IRP ensure resource adequacy and capacity. MCL 460.6t(8)(a)(i). MNS also argues that Mr. Jester and Mr. Blumenstock refuted Mr. King's calculations and arguments. MNS' initial brief, p. 23 (citing 10 Tr 4354-4356, 4130-4134).

Finally, MNS points to the diversity of the parties that are signatories to the settlement agreement as evidence that the agreement is in the public interest and argues that, by comparison, the objecting parties' interests are relatively narrow. MNS asserts that Energy Michigan is a trade group with narrow business interests; WPSC is a power supply cooperative with a contractual

interest in opposing the Campbell retirement; the BMPs seek only to extend their PPAs with Consumers; and Mackinac submitted no evidence and evinces only an ideological opposition to closing coal plants. MNS' initial brief, pp. 25-27. MNS argues that the settlement agreement satisfies the Rule 431 criteria and should be approved. *Id*., pp. 27-28.

3. Mackinac Center for Public Policy

Mackinac argues that the Commission should reject the settlement agreement because it does not represent "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs" as required in the language of MCL 460.6t(8)(a). Mackinac's initial brief, p. 3 (quoting MCL 460.6t(8)(a)). Mackinac also contends that the settlement agreement does not meet the requirements of Rule 431(5) because it is not in the public interest and is not supported by substantial evidence on the record. Mackinac's initial brief, pp. 4-5.

Mackinac asserts that the settlement agreement is not in the public interest because it presents a risk of "systemwide instability and rapid price swings." *Id*., p. 5. Mackinac states that this is partially due to the overreliance in the settlement agreement on acquiring additional power from the MISO market. Mackinac quotes from its exceptions to argue that MISO does not have sufficient capacity to serve the relevant demand. Mackinac asserts that the settlement agreement could cause reliability problems in MISO Zone 7 if early plant closures are "allowed to move forward without sufficient replacement capacity." Mackinac's initial brief, p. 7 (quoting Mackinac's exceptions, p. 7). Mackinac "acknowledge[s] that the proposed Settlement Agreement addresses this somewhat by acknowledging that Karn Units 3 and 4 may be required to stay in operation," but argues that the settlement agreement does not do enough to alleviate the concern about "systemwide instability and rapid price swings." Mackinac's initial brief, p. 8. Mackinac

argues that the recent results of the MISO Planning Resource Auction for Zone 7 show the potential for a shortfall.[3]

Mackinac further states that the settlement agreement fails to consider the recent volatility of natural gas prices. Mackinac argues that natural gas plays a "heavy role" in the settlement and thus natural gas pricing should be central to the Commission's decision. *Id.*, p. 10. Mackinac again quotes extensively from its exceptions and argues that the settlement agreement fails to address the concerns that were laid out in the exceptions. Mackinac asserts that Henry Hub prices are at "near-historic levels" and that the price of coal compares favorably to natural gas. *Id.*, pp. 14-15. Mackinac asserts that "a reasonable and prudent path would be to rework the Company's modelling scenarios with more realistic natural gas prices." *Id.*, p. 15.

Mackinac further expresses concern that:

> [p]er the Proposed Settlement Agreement, the Company will spend over $30 million ratepayer dollars establishing programs specifically designed to limit customer access to electricity services during periods of higher demand (cold or hot weather): $23,751,000 for demand response programs, and $9,736,315 for conservation voltage reduction. These expenditures are deemed necessary because the Company is working from its wholly voluntary plan to reach net-zero CO2 emissions by designing a system that will be unable to meet customer demand, especially during periods of extreme weather.

Id., p. 16 (citing Settlement Agreement, p. 4). Mackinac continues, arguing that the settlement agreement fails to address the issues of restricted supply chains and significant price increases for certain minerals such as lithium, cobalt, and nickel. Mackinac posits that Consumers' planned expansion of the use of batteries will still be insufficient to provide the necessary backup power

[3] Mackinac's initial brief contains numerous links to publicly available documents sourced from governmental entities or the media. None of the referenced documents are part of the record in this case. Mackinac did not present evidence in either the primary phase or the contested settlement phase of the case.

during extended periods of inclement weather, and that, in any case, developing a sufficient level of backup battery power would be prohibitively expensive. Mackinac asserts that the settlement agreement also fails to consider the significant environmental costs associated with Consumers' goal of becoming carbon neutral by 2040, which, Mackinac insists, will add to the growing level of "industry-wide instability, insolvencies, supply chain issues, and stalled development projects in the solar and wind industries." Mackinac's initial brief, p. 19.

Mackinac states that, under Section 5 of the settlement agreement, Consumers will be transferring stranded costs associated with Campbell Units 1, 2, and 3 to ratepayers as well as decommissioning costs (after a reasonableness and prudence review). Mackinac opines that an increasing level of instability is being designed into Consumers' system through the loss of large, dispatchable generation sources which are replaced by what it refers to as "weather-dependent and non-dispatchable renewable sources." *Id*., pp. 9, 19-20.

Mackinac argues that Consumers' proposed donations to low-income programs are "a band-aid solution to the problems caused by its own decision to impose on ratepayers the cost of its wholly voluntary goal of net-zero emission by 2040 goals, as well as the systemwide costs associated with weather-dependent and variable renewable energy sources." *Id.*, pp. 20-21 (footnote omitted). Mackinac concludes that:

> The Company is developing and constructing a system that precludes the use of coal and nuclear and relies solely on wind, solar, storage, and (over the upcoming two decades) slowly decreasing levels of natural gas for actual generation of electricity services for customers. Other programs such as EWR, CVR, and demand response target reduced supply and use by customers of electricity services, not the actual provision of electric service to customers. Mackinac Center objects to these measures.

Id., p. 21.

4. Michigan Energy Innovation Business Council, Institute for Energy Innovation, and Clean Grid Alliance

EIBC/IEI/CGA support the settlement agreement, noting that Rule 431 encourages parties to enter into settlement agreements when possible. EIBC/IEI/CGA contend that the settlement agreement meets all of the criteria for an approvable settlement under Rule 431(5) because the objecting parties were given a reasonable opportunity to present evidence and argument in opposition; the public interest is represented by the parties who entered into the agreement; and the settlement agreement is a fair and reasonable resolution of the proceeding that is supported by substantial evidence on the record. EIBC/IEI/CGA note that discovery continued during the contested settlement phase of the case and cross-examination took place. EIBC/IEI/CGA's initial brief, pp. 5-6. They also note the testimony from the Staff regarding the cross-section of signatories to the agreement, including parties who represent residential customers, commercial and industrial customers, advanced energy sector businesses, environmental groups, a transmission company, and third-party developers. *Id*., p. 7 (citing 10 Tr 4407-4408). EIBC/IEI/CGA note that, under Section 6.b.ii. of the settlement agreement, Consumers is making a commitment to acquiring new clean energy resources of up to 200 ZRCs through PPAs or other third-party agreements. EIBC/IEI/CGA's initial brief, p. 7.

Responding to the objection that the settlement agreement will result in serious supply chain issues, EIBC/IEI/CGA opine that the settlement agreement turns these risks into opportunities by calling for better utilization of "Michigan manufactured components and low-carbon manufacturing" in the competitive bidding process. EIBC/IEI/CGA's initial brief, p. 8 (quoting Settlement Agreement, p. 9). EIBC/IEI/CGA aver that the concerns about pricing that have been expressed by the objectors are addressed by Consumers' commitment to continue the 50/50 company-ownership to third-party ownership construct that was approved in Case No. U-20165.

EIBC/IEI/CGA's initial brief, pp. 9-10. EIBC/IEI/CGA conclude that the settlement agreement meets the requirements of Rule 431(5) and should be approved. *Id*., pp. 10-11.

5. Michigan Department of Attorney General

The Attorney General states that her primary concerns with Consumers' IRP are affordability, reliability, and the use of sustainable sources of energy. She contends that the settlement agreement addresses all three of these concerns. The Attorney General notes that the settlement agreement provides for the closure of Consumers' remaining coal plants and argues that this benefits public health and is consistent with Governor Whitmer's MI Healthy Climate Plan. Attorney General's initial brief, p. 8 (citing 10 Tr 4375, 4327-4330, and 4122).

Beginning with affordability, the Attorney General notes that evidence shows that the early retirement of the Campbell plant will save ratepayers $150 million in avoidable capital expenditures. Attorney General's initial brief, p. 9 (citing 10 Tr 4327). She argues that the settlement agreement also saves money for ratepayers by eliminating Consumers' proposal to acquire the affiliated CMS plants, which avoids the potential $515 million in immediate costs as well as future retirement costs and the unrecovered book value of Karn Units 3 and 4. Attorney General's initial brief, pp. 9-10 (citing 10 Tr 4334-4335). The Attorney General further notes that, with respect to the regulatory asset, the settlement provides for a WACC of 9.0% rather than the current ROE of 9.9%, also benefiting ratepayers. And finally, the settlement agreement provides for assistance to low-income ratepayers with direct funding of $5 million this year and another potential $2 million annually over the next 14 years. Attorney General's initial brief, p. 10.

Addressing reliability, she contends that the settlement agreement provides for adequate existing and new resources to meet capacity needs. Attorney General's initial brief, p. 11 (citing 10 Tr 4330-4335, 4406, 4224-4229, 4139, and 4142-4144). The Attorney General points to the

continued availability of Karn Units 3 and 4, as well as the solicitation for PPAs that will provide up to 700 ZRCs of energy and capacity beginning in 2025. She also cites to the provision that Consumers seeks 2 additional GW of new solar energy and undertake a battery storage program. Attorney General's initial brief, p. 11 (citing 10 Tr 4339). The Attorney General further states that:

> the Settlement Agreement requires the Company to conduct certain evaluations and take other actions prior to the next IRP that can lead to benefits for ratepayers including, but not limited to, developing a distributed generation resource model; gathering input from the public before filing its next IRP; gauging interest in combined heat and power resources and model for the next IRP proceeding; providing total emissions for certain pollutants in the next IRP case; presenting PM2.5-related health impacts from power plant emissions in the next IRP case; conducting environmental justice screenings near power plants; and reporting on low-income customers[']' participation in energy reduction and load reduction activities and rooftop solar adoption.

Attorney General's initial brief, pp. 11-12 (citing Settlement Agreement, pp. 12-16). The Attorney General urges the Commission to approve the settlement agreement.

6. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

The CEOs take the position that the contested settlement agreement is in the public interest and supported by record evidence. The CEOs contend that the settlement supports the public interest because: "(1) it aligns with important climate action goals intended to protect Michiganders; (2) it improves economic and public health outcomes; and (3) it includes beneficial modeling and community engagement commitments for the Company's next IRP." CEOs' initial brief, p. 6 (quoting 10 TR 4375). The CEOs posit that "the Settlement Agreement is consistent with Governor Whitmer's MI Healthy Climate Plan, and is responsive to the urgency of addressing climate change." *Id*. The CEOs opine that the settlement agreement balances the cost to Consumers associated with retirement of its coal plants with the impacts on low-income

customers. CEOs' initial brief, p. 6 (citing 10 TR 4376). The CEOs state that expert testimony in the record demonstrates avoided negative health outcomes as a benefit of the early coal plant retirements and that significant public health and environmental concerns associated with acquiring the DIG facility are avoided under the settlement agreement. CEOs' initial brief, pp. 6-7. Finally, the CEOs aver that the settlement agreement has important implications for future IRPs including the commitments to model distributed generation as a resource, conduct public health and environmental justice analyses, and provide expanded opportunities for community input and public participation. *Id*., p. 7 (citing 10 Tr 4376). The CEOs argue the Commission should find the settlement agreement to be in the public interest.

7. Hemlock Semiconductor Operations, LLC

HSC supports the settlement and recommends that the Commission approve it. HSC's initial brief, p. 2. HSC opines that "parties were given a reasonable opportunity to present evidence and arguments in opposition to the record." *Id*., p. 4. HSC posits that the public interest was adequately represented by parties entering into the settlement agreement as "the signatories to the Settlement Agreement represent a broad cross-section of interests . . . ." *Id*., p. 5. HSC also notes that "the Michigan Court of Appeals has affirmed a Commission determination that the public interest was adequately represented by the Staff when the Staff was a party to a contested settlement agreement." *Id*. (citing *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93094; 602 NW2d 225 (1999) (*Attorney General*). HSC opines that "all the parties who filed testimony in opposition to the settlement represent competitors of Consumers. In each case, the objecting party is seeking to advance its own particular interest, and not the public interest." HSC's initial brief, p. 6 (footnote omitted). HSC submits that the settlement agreement is a fair and reasonable resolution of the proceeding as "Consumers and others presented testimony and

arguments that the Settlement Agreement reflects significant compromise by all involved" which is "evident when comparing the details of Consumers' initial PCA with the terms of the proposed Settlement Agreement." *Id*. Finally, HSC posits that the settlement agreement is supported by 315 pages of transcript and 23 exhibits while the principal record in this case consisted of 4,094 pages of transcript across 9 volumes and over 500 exhibits. *Id*., p. 7. HSC concludes that the settlement agreement "is supported by substantial evidence on the record and should be approved." *Id*.

8. The Commission Staff

In response to the concerns raised regarding resource adequacy, the Staff responds "that this settlement agreement appropriately balances the resource adequacy concerns of Zone 7, Consumers' need to serve the load and demand of its customers, and the benefits of Consumers' decision to work towards becoming carbon neutral by 2040." Staff's initial brief, p. 4 (citing Settlement Agreement, p. 13). The Staff notes that its testimony highlights the addition of the Covert plant and the investments in renewable generation. *Id*. The Staff notes its concerns regarding resource adequacy of Zone 7, but states that:

> it also understands that Consumers Energy is not tasked with providing resource adequacy for the entirety of Zone 7 at the sole expense of Consumers' ratepayers. Staff expects all load serving entities within MISO Zone 7 to contribute the necessary capacity to meet capacity obligations at MISO and through Michigan's State Reliability Mechanism (MCL 460.6w) and that these load serving entities will make the necessary investments to ensure that all customer needs within the zone are fully planned for. Therefore, Staff recommends that the Commission find that this settlement agreement appropriately balances the reliability needs of Zone 7 and the needs of Consumers' ratepayers.

Staff's initial brief, p. 5. The Staff reiterates that while the CMS plants "can bid into one tranche of the solicitation, the CMS [plants] are only able to bid in for the capacity they have available that is not currently contracted for" which "constitutes less than 500 ZRCs in 2025." *Id*., p. 6 (citing

Settlement Agreement, pp. 6-7; 3 Tr 138, 366). The Staff also states other resources, such as distributed energy resources, may be available by 2025, and are not currently counted within Zone 7. Further, the Staff reiterates testimony indicating "that the second tranche of the solicitation will likely result in additional new resources." Staff's initial brief, p. 6.

In response to the BMPs, the Staff states that, while the biomass plants are reliable resources, the Commission cannot modify the proposed settlement agreement to extend the PPA's to 2035, because the settlement agreement is not severable, and any modification or rejection of a provision deems the settlement agreement to be withdrawn. Further, the Staff indicates that the biomass plants are able to participate in the one-time solicitation as set forth in the settlement agreement. *See*, *id*., p. 7.

9. Consumers Energy Company

Consumers contends that the settlement agreement satisfies the requirements of Rule 431. Consumers' initial brief, p. 10. Consumers argues that the signatories of the settlement agreement adequately represent the public interest and reiterates testimony from its witness, Mr. Torrey, "on the nature, scope, and diversity of parties' interests . . . ." in this case. *Id*., p. 11. Consumers also quotes testimony from the Staff's witness, Mr. Proudfoot, that "the 18 parties that signed 'represent most, if not all, of Michigan's sectors concerned with the future of energy related issues,' thus satisfying the requirement that the parties represent the public interest." *Id*., p. 11 (quoting 10 Tr 4408). Consumers posits that Mr. Torrey's and Mr. Proudfoot's testimony demonstrates that "the signing parties 'represent a broad, diverse group of parties advocating for the economic and environmental interests of Consumers Energy's electric customers and the state of Michigan,' who are also focused on ensuring the Company's customers are provided with reliable electricity." Consumers' initial brief, p. 11 (quoting 10 Tr 4257).

Consumers contends that "[t]he Commission should consider the four parties that signed statements of non-objection to the Settlement Agreement in reaching a finding that the Settlement Agreement adequately represents the public interest because those parties, having had an opportunity to contest the Settlement Agreement, elected not to do so." Consumers' initial brief, p. 12. Similar to HSC, Consumers posits that "[t]he Michigan Court of Appeals has upheld the Commission's finding that a utility's and Staff's involvement in a settlement agreement can be sufficient to ensure that the public interest is adequately represented and also found that that 'participation of fewer than all interested parties in the negotiation does not mandate a conclusion that the signatories to the settlement did not represent the public interest." *Id*. (quoting *Attorney General*, p. 94). Consumers concludes that "[t]he factual circumstances presented in this proceeding meet and exceed the Commission's requirement for ensuring that the settling parties adequately represent the public interest." Consumers' initial brief, p. 12.

Consumers notes that of the four parties opposing the settlement agreement—Energy Michigan, Mackinac, WPSC, and the BMPs—only three filed testimony in the present case. *Id*., p. 13. Further, Consumers argues that "[u]nlike the broad and diverse group of parties who signed the Settlement Agreement, the three parties who submitted testimony opposing the Settlement Agreement are all business competitors of Consumers Energy." *Id*. (citing 10 Tr 4262). Consumers reiterates its testimony that:

> Energy Michigan and Wolverine would benefit financially from the opportunity created in this proceeding to procure surplus capacity to meet their own customers' needs at a lower cost than building their own. The BMPs would also benefit financially if they received contract extensions at the expense of other resources which make up the PCA. That kind of motivation represents the opposite of the public interest.

Consumers' initial brief, p. 13 (quoting 10 Tr 4263). Consumers concludes that "the broad-based coalition of parties who signed the Settlement Agreement and the parties who signed statements of

non-objection are a far better representation of the public interest in this proceeding than the parties who oppose it." Consumers' initial brief, p. 13 (citing 10 Tr 4263).

Consumers argues that the settlement agreement represents a fair and reasonable resolution to the proceedings as it "represents a significant compromise that was negotiated in good faith and proposes to resolve this matter based on the positions of the parties in the record." Consumers' initial brief, p. 14. Consumers avers that the settlement agreement meets the requirements for approval set out under Section 6t of Act 341. Specifically, Consumers posits that "all 18 signing parties agree that the PCA, as provided in the Settlement Agreement, represents the most reasonable and prudent plan to meet the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons" as required by Section 6t(8)(a) of Act 341. *Id*. Consumers reiterates testimony by company witness Blumenstock on the settlement agreement's compliance with Section 6t(8) of Act 341, including how the settlement agreement: (1) ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and LCR; (2) ensures compliance with applicable state and federal environmental regulations; (3) ensures competitive pricing; (4) ensures reliability; (5) addresses commodity price risk and ensures diversity of generation supply; and (5) proposes reasonable and cost effective levels of peak load reduction (DR, CVR, EWR). *See*, Consumers' initial brief, pp. 14-19. Consumers cites to testimony by the Staff that the company's IRP PCA as revised by the settlement agreement meets the requirements of Act 341 as additional support. Consumers' initial brief, pp. 19-20.

As noted above, Consumers argues that the settlement agreement "was supported in the extensive record created in the proceedings leading up to the filing of the Settlement Agreement, which consisted of over 4,000 pages of testimony and over 500 exhibits" as well as the additional

evidence provided on the contested settlement. *Id*., p. 20. Consumers notes the position of company witness, Mr. Blumenstock, MNS, and the Staff that the settlement agreement is supported by substantial evidence in the record as a whole. Consumers quotes the Staff's testimony that:

> As stated above, the record in this case is substantial. All issues addressed in the [Settlement Agreement] have been addressed in testimony, rebuttal, brief, exceptions, and robust discovery. The [Settlement Agreement] was filed after a full record has been developed in this case. Therefore, based on all of the above, it is Staff's opinion that this [Settlement Agreement] meets the requirements of Rule 431.

Id., p. 21 (quoting 10 Tr 4408). Further, Consumers posits that "certain objecting parties have also attempted to interject issues into this contested settlement proceeding which are not based on the initial record at all." Consumers' initial brief, pp. 21-22. Specifically, Consumers references WPSC's reliance on the company's December 1, 2021 capacity demonstration in Case No. U-21099 and the BMPs' proposal that the settlement agreement be modified to require Consumers to extend their PPAs with the represented plants. *Id*., p. 22. Consumers concludes that the settlement agreement "is in the public interest, represents a fair and reasonable resolution of the proceedings, and is supported by substantial evidence on the record as a whole" and thus "it should be approved by the Commission in its entirety without and modifications or conditions." *Id*.

Turning to the arguments of the individual objecting parties, Consumers argues that these objections fail to provide grounds to reject or modify the settlement agreement. *Id*., p. 23. Consumers opines that these "arguments demonstrate a self-interested concern that the Settlement Agreement will challenge their ability to profit off Consumers Energy and its customers and Michigan's hybrid deregulation construct." *Id*. Addressing WPSC's position that the settlement agreement will negatively impact reliability, Consumers avers that the settlement agreement "will

bring at least 2,084 ZRCs into MISO LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ of nearly 700 ZRCs (at least)." *Id*., p. 24. Consumers posits that "[t]his increase will enable the Company to manage any challenges or delays associated with bringing new resources online, changes in MISO's planning requirements that may impact the Company's PRMR, the migration to a seasonal capacity construct, and any degradation that might be applied to solar capacity accreditation." *Id*. Consumers then addresses claims regarding reliability and resource adequacy of WPSC, Energy Michigan, the BMPs, and Mackinac individually. *See*, Consumers' initial brief, pp. 24-56. As these positions are thoroughly outlined above, they will not be repeated here.

Consumers concludes that "the intent and focus of the Company's original PCA were maintained" by the settlement agreement "ensuring the Company's clean energy transition, as initially set forth in the Company's 2018 IRP." Consumers' initial brief, p. 56. Consumers argues that the PCA, as modified by the settlement agreement will "help lead a faster clean energy transformation by accelerating the Company's exit from coal-fired generation in 2025 while increasing reliability and providing resource adequacy for customers." *Id*. The company provides that "the Settlement Agreement will continue the Company's competitive procurement of clean energy resources by procuring approximately 8,000 MWs of solar resources by 2040 and will also accelerate the deployment of battery storage." *Id*., pp. 56-57. Finally, "like the Company's initially filed plan, the PCA, as modified in the Settlement Agreement, continues to save customers money–providing for customer savings of nearly $600 million." *Id*., p. 57.

Consumers asserts that the settlement agreement "meets the requirements of the Commission's rule for approving contested settlement agreements, Rule 431, and the requirements for approving an IRP under Section 6t." *Id*.

10. The Biomass Merchant Plants

The BMPs first summarize the contested settlement agreement before turning to the issue of the scope of the proceeding. The BMPs aver that their position is not beyond the scope of this IRP proceeding as their "objections in this proceeding are that the modified IRP fails specific statutory requirements of MCL 460.6t(8)" and that the "most reasonable and prudent means" under the statute requires the review of alternative plans which is what the BMPs offered in this case. BMPs' initial brief, p. 6, 8 (emphasis omitted). The BMPs reiterate their objections, which were overruled by the ALJ to the company's testimony, again claiming they did not have an opportunity to respond. *See*, *id*., pp. 9-10.[4]

The BMPs argue that the settlement agreement fails the resource adequacy and reliability requirements under the statute as there is a shortfall in ZRCs. Thus, the BMPs state that the settlement agreement should be modified because "[c]ontinuing to purchase capacity and energy from the BMPs through 2035 would, in fact, correct both that statutory defect and the Company's strategic goal." *Id*., p. 11. The BMPs further argue that the settlement agreement also fails to recognize the likelihood of the reduction of solar accreditation "down as low as 30% in the next

[4] The Commission notes that the BMPs made several references to appealing evidentiary rulings throughout its initial brief. *See*, BMPs' initial brief, pp. 9, 10, 36, 42-43. The Commission's rules set forth the standard for appealing rulings of presiding officers. *See*, Mich Admin Code, R 792.10433 (Rule 433). In part, Rule 433(3) states that "[a]n offer of proof shall be made in connection with an appeal of a ruling excluding evidence" and that "[i]f the ruling excluded written evidence or evidence that refers to documents or records, the offer of proof shall consist of a copy of the evidence, documents, or records." In addition, Rule 433(4) states that an application for appealing a ruling of a presiding officer "shall be supported by a clear and concise brief, pursuant to the provisions of R 792.10434, stating the basis for the appeal and showing that it complies with the provisions of this rule. The brief shall be supported by specific factual allegations as appropriate." The Commission finds that the BMPs have not met these minimum standards set forth under Rule 433. Therefore, the Commission denies any appeal of rulings made by the presiding officer in this proceeding as set forth in the BMPs' initial brief.

several years." *Id*., p. 12 (footnote omitted). The BMPs reiterate the testimony to aver that resource adequacy concerns are compounded by issues surrounding solar and battery storage and that the settlement agreement fails to address "the question of what energy is being stored, solar or fossil fuel generated energy. Solar energy can only be stored if that solar production exceeds load. If the load exceeds the solar generation, the energy being stored is from fossil fuel generation." *Id*., p. 15.

The BMPs reiterate their concern regarding Consumers' "use of an incorrect solar capacity factor" which it avers "is 20.6% greater than the average capacity factor of all solar generation facilities currently operating in Consumers' service territory." *Id*., pp. 4, 17. The BMPs state "[i]n contrast to the proposed solar capacity, the generation from the Biomass Plants is well known and MISO is not considering revisions to their ZRC accreditations." *Id*., p. 22.

Citing MCL 460.6t(8)(b), ED 2020-10, and the IRP filing requirements, the BMPs argue that "despite the fact that the Biomass Plants are located within Consumers' service territory," the settlement agreement disregards "the economic impact of the potential closure of those plants on the communities in which they are located." BMPs' initial brief, pp. 22-23. Therefore, the BMPs aver that the settlement agreement violates the statutory mandate because it "chooses to import energy into Michigan from other states" and "supports out-of-state construction and production rather than in-state construction, construction upgrades, construction maintenance and in-states generation." *Id*., p. 24.

The BMPs contend that the settlement agreement also does not meet the requirements in MCL 460.6t(8)(a)(v) because it fails to address potential future lack of capacity and that any early retiring plant could be designated as a system support resource (SSR), requiring it to remain in operation and that the "designation costs can run into significant millions of dollars." BMPs'

initial brief, pp. 25-26. Similarly, under MCL 460.6t(8)(a)(vi), the BMPs aver that the settlement does not "appropriately balance the diversity of generation resources" which "impacts that commodity price risk" under MCL 460.6t(a)(v). BMPs' initial brief, p. 26. The BMPs reiterate the record testimony to support this contention arguing that "the first tranche of the One Time Solicitation will almost certainly result in Consumers acquiring natural gas capacity" which will likely include the CMS plants, "all of which are natural gas fired generation" and that this "concentrated amount of natural gas fired generation has commodity price risk . . . ." *Id*., pp. 27-28.

The BMPs restate the position that Consumers has inappropriately excluded generation from the biomass plants from the settlement agreement and that the company improperly relied on "the cost of new Biomass construction even though the Biomass Plants are existing construction, not new construction." *Id*., p. 30 (emphasis omitted). Reiterating record testimony, the BMPs aver that the settlement agreement violates the "statutory obligation under MCL 460.6t(1)(f)(iii) to include 'any supply-side and demand-side resources that reasonably could address any need for additional generation capacity . . . .'" BMPs' initial brief, p. 33. The BMPs further claim that the biomass plants are excluded from the one-time solicitation based upon the criteria set forth in the settlement agreement. *See*, *id*., pp. 35-38.

The BMPs contend that the settlement agreement violates ED 2020-10 and Michigan's Healthy Climate Plan. *Id*., p. 38. In support of this position, the BMPs state:

> The Settlement Agreement simply fails to consider the environmental benefits of the Biomass Plants as compared to the non-intermittent fossil fuel generation that will be acquired under the IRP as modified by the Settlement Agreement. It also fails to consider the unequaled ability of the Biomass Plants to help Consumers reach the goals of both Executive Directive 2020-10 and Michigan Healthy Climate Plan. The Biomass Plants' fuel composition is described in detail in Mr. Polich's testimony. The Biomass Plants are not only net-zero carbon generation, they have

> the further benefit of preventing the release of Methane from decomposing forest wood waste into the atmosphere.

BMPs' initial brief, p. 40 (footnote omitted). The BMPs further argue that the environmental benefits of biomass fueled generation include a much smaller land use than solar and that "[c]ontinuing to purchase 188 MW of energy from the existing Biomass Plants means that between 1,128 to 1,504 acres of land can be left undisturbed by an equivalent amount of solar projects." *Id*., p. 42.

The BMPs restate that the ALJ erred in numerous evidentiary rulings including sustaining objections and limiting the time for cross-examination. *See*, *id*., p. 43. In conclusion, the BMPs "object to the Settlement Agreement as presented and request that it be amended to include a provision pursuant to which Consumers will continue to purchase capacity and energy from the Biomass Plants after the end dates of their current contracts until 2035." *Id*., p. 44.

11. Citizens Utility Board of Michigan

CUB argues that the settlement agreement improves upon Consumers' original PCA and is in compliance with Rule 431. CUB states that the settlement agreement improves the PCA as it improves the future analyses of marginal line losses and avoided transmission and distribution costs and that:

> [w]hile the Settlement Agreement does not require Consumers to reevaluate residential DR potential in this IRP . . . its commitment to collecting and reporting valuable marginal line loss data and including marginal line losses and avoided T&D costs in its evaluation of all distributed resources in future IRPs is a fair and reasonable compromise.

CUB's initial brief, p. 3. CUB also notes that the settlement agreement removes the 20% FIM Consumers was seeking in this proceeding. *Id*.

CUB notes that the parties signing the settlement agreement "represent a broad spectrum of the public interest, including the interests of residential ratepayers, commercial and industrial

ratepayers, businesses, and environmental groups" demonstrating the public interest is adequately represented. *Id*., p. 4 (citing 10 Tr 4407-4408). CUB reemphasizes its testimony and avers that the substantial record demonstrates that the settlement agreement "and provides a fair and reasonable resolution of their respective concerns in this proceeding." *Id*., p. 5. Finally, CUB states that "the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition" to the contested settlement agreement, therefore satisfying all requirements of Rule 431. CUB's initial brief, p. 6.

12. Wolverine Power Supply Cooperative

WPSC argues that the settlement agreement fails to meet the requirements of Rule 431. WPSC avers that the settlement agreement is not in the public interest as it will allow the retirement of Campbell 3 in 2025 which "will further stress Michigan's already-strained grid system" and that this "fails to represent a fair and reasonable resolution to the proceeding." WPSC's initial brief, pp. 2-3. Pointing to the record and the PFD, WPSC states that a 2025 retirement of Campbell 3 is not well-supported. WPSC argues that approval of the settlement agreement "requires a set of parallel, perfect, and, therefore, unlikely outcomes" and lists those outcomes as follows:

> (1) despite MISO's projections, Zone 7 realizes sufficient resources to serve Michigan, (2) Consumers realizes declining load growth, despite economic projections and announced load growth; (3) Consumers' one-time solicitation is fully successful in acquiring 700 incremental Zonal Resource Credits ("ZRC") that are installed and delivered in less than three years, and (4) Consumers realizes the outcome of its modeling—a complete disconnection from the rest of Michigan's grid.

Id., p. 3 (footnote omitted).

WPSC states that:

> [w]hen reviewing more current data from Consumers' own capacity demonstration filing in Case No. U-21099, which shows a 271 ZRC deficit in 2022 or 425 ZRC

> lower than the PCA even with the same supply mix, . . . unless it acquires a material portion of the solicitation, Consumers will be capacity negative in 2025, even with the Covert purchase and keeping Karn Unit 3 and 4 online through 2030. (Testimony of Thomas King, 10 Tr 4303; Rebuttal Testimony of Thomas King, 10 Tr 4311-4312.)

Id., p. 4 (emphasis in original). WPSC further argues that the settlement agreement's effort of allowing a one-time solicitation of 700 ZRCs to combat reliability concerns from the early retirement "does not ensure Consumers customers are shielded from resource adequacy shortfalls in Zone 7 – the projects must actually be built and the 700 ZRCs of dispatchable and intermittent resources likely cannot be built in time." *Id*., p. 4. Continuing, WPSC points out that "the proposed solicitation will not create any incremental (i.e., new) Zone 7 capacity" and is merely another path to utilize the CMS plants as originally proposed in the PCA. *Id*. Reiterating its testimony, if Campbell 3 is replaced with existing Zone 7 capacity there will be a net negative capacity position in the zone which, WPSC avers "places Michigan on a path toward load shed (e.g., blackouts) that is likely to harm Michigan residents." *Id*., p. 6 (citing 10 Tr 4312).

WPSC reiterates its testimony that, despite Consumers' assumption, the market reality is that there is a declining PRMR between 2022 and 2025, and that it "it conflicts with MISO's statements of increasing load forecasts." *Id*., p. 7 (citing 10 Tr 4305 and Exhibit WPSC-6). WPSC further points to developmental projects which will result in incremental load increases and argues that Consumers' estimates of increases in DR are not supported by any evidence indicating that such is possible. WPSC further states that the company's assurances that there is time to address the shortfall in the future is insufficient and that "it is unreasonable for Consumers to utilize an unsupported, lower reserve margin for the future." *Id*., p. 8.

WPSC further argues that, while the first 500 ZRCs for the proposed solicitation are likely to come from existing Zone 7 resources, "the second tranche of 200 ZRCs are likely to be procured

from intermittent resources" and that "[t]he record is devoid of evidence regarding where the needed resources would come from." *Id*., p. 9 (citing 10 Tr 4312). WPSC states that the denial that the solicitation is speculative "demonstrates a fundamental misunderstanding of the current renewables landscape" and even as "more solar resources are added to the grid, less benefit is realized and the solar capacity accreditation declines to match performance." *Id*. (citing Exhibit WPSC-8). WPSC reiterates its position that the 500 MW is unreasonable noting that:

> [e]ven if the proposed 500 MW of projects were able to procure materials and Consumers is capable of acquiring and utilizing the nearly 3,500 necessary open acres of Michigan land, the projects would also need to achieve the local government approvals, complete MISO's byzantine generation queue process, and complete transmission improvements necessary to facilitate construction and interconnection—all within the limited time available.

Id., p. 10.

In addition, WPSC avers that the settlement agreement inappropriately requires Consumers to be treated as an island rather than an integrated and interconnected participant in the Michigan electric grid. WPSC argues that "[g]iven the likely capacity shortfall in Zone 7, the [settlement agreement's] failure to address transmission deficiencies will exacerbate the problems created by hastily retiring generation resources. If one of the few existing ties fail or export capability from other areas is reduced, the only other option will be load shed." *Id*., p. 11 (footnote omitted).

WPSC concludes that, under Rule 431, the Commission must deny the settlement agreement as it "is not supported by *any* evidence within the record, and certainly is not supported by *substantial* evidence on the record" but rather that the record demonstrates additional modeling and analysis is needed to support an early retirement of Campbell Unit 3. *Id*., p. 12 (emphasis in original). WPSC further states that "[r]ushing the retirement of Campbell Unit 3 may allow the Commission to continue forward with its admirable goal of reducing Michigan's carbon emissions, but it will come at the risk of electric reliability and related health and safety of

Michiganders." *Id*. WPSC avers that the settlement agreement does not reflect the most reasonable and prudent path and that the Commission should "require Consumers to keep Campbell Unit 3 in operation, at least until Consumers can present hard data that verifies that Campbell Unit 3 can be retired without jeopardizing reliability and, as the PFD notes, Consumers has not modeled or analyzed these issues sufficiently." *Id*., p. 13.

13. Urban Core Collective

UCC filed a statement in support of the settlement agreement in lieu of an initial brief to reaffirm its initial support as a signatory to the settlement agreement. *See*, Case No. U-21090, filing #U-21090-0857.

D. Reply Briefs

1. Michigan Environmental Council, Natural Resources Defense Council, Inc., Sierra Club, and Citizens Utility Board of Michigan

In reply to Energy Michigan, MNS argues that Energy Michigan errs in positing that the considerations under MCL 460.6t(8) somehow trump the Rule 431 criteria. MNS' reply brief, pp. 2-3. MNS notes that the Michigan Administrative Procedures Act (APA) also addresses settlements and provides that contested cases may end in settlement when agreed to by the parties in MCL 24.278(2). *Id*., p. 3. MNS contends that Rule 431 implements this statutory requirement. While agreeing with Energy Michigan that it is important to harmonize the IRP statute and Rule 431, MNS contends that Energy Michigan's reading of MCL 460.6t(8) would make applying the requirements of Rule 431 an "empty exercise." *Id*., p. 4. MNS further contends that Energy Michigan's argument conflicts with the Commission's approval of the contested settlement in Case No. U-20165. *Id*. (citing June 7, 2019 order in Case No. U-20165, p. 76 (June 7 order); *see also*, June 7 order, p. 91).

MNS states that it addressed Energy Michigan's resource adequacy and pricing arguments in its initial brief, and notes that Energy Michigan was included in all settlement discussions, asserting that Energy Michigan was included in multiple emails regarding the settlement conference which took place in February 2022. MNS' reply brief, p. 5.

In reply to WPSC, MNS again argues (as it did in its initial brief) that, contrary to WPSC's assertions, the settlement agreement will actually improve resource adequacy in Zone 7. MNS again points to the 1,114 ZRCs from the Covert gas plant, 71 ZRCs of new battery storage, 250 ZRCs of new solar generation, and 94 ZRCs of new demand side resources, and states that "[e]ven with the retirement of the Campbell coal units, these resource additions will result in an overall net increase in Zone 7 resources." *Id.*, p. 7 (citing 9 Tr 5-6, 10 Tr 4350, and Settlement Agreement, Sections 1-3); *see also*, 10 Tr 4405-4406. MNS further argues that WPSC's repeated citations to the PFD for support are inapposite since the PFD evaluated the original PCA, which presented actual resource adequacy concerns. MNS' reply brief, pp. 8-9.

MNS contends that the Commission should not consider the websites and news stories cited by WPSC regarding the PRMR because they are not part of the record, and, in any case, Mr. Jester, Mr. Proudfoot, and Mr. Clark rebutted these concerns. MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407) (citing 10 Tr 4358-4359 and 4227-4228). MNS notes that Mr. Proudfoot testified that:

> The reserve margin used by the Company in its capacity demonstration for 2025 comes directly from the 2022-2023 MISO Loss of Load Expectation (LOLE) Study Report. It is also worth noting that assuming a constant reserve margin of 8.7% instead of 7.4% would represent about 100 MW of additional obligation to the Company. The differences between Karn Units 3 & 4 and the CMS capacity is still likely enough to cover this difference, even without counting any additional capacity from the one-time solicitation.

MNS' reply brief, p. 10 (quoting 10 Tr 4406-4407). MNS asserts that WPSC's claims about Consumers being capacity negative are simply untrue as shown by the list of ZRCs described above, and states that "Consumers would still have a surplus even if both tranches of the one-time solicitation fail entirely: in that extremely unlikely scenario, Consumers would still have a 514 ZRC surplus in 2025/26." MNS' reply brief, p. 11 (citing 10 Tr 4354). Finally, on this issue, MNS avers that Mr. Jester showed that Mr. King's calculations were incorrect because Mr. King assumed that Karn Units 3 and 4 would be operating in the 2025/2026 planning year. MNS' reply brief, p. 12 (citing 10 Tr 4355). MNS notes that WPSC fails to cite to any record evidence showing that the retirement of Campbell Unit 3 in 2025 is unsupported. MNS' reply brief, p. 12.

In reply to the BMPs, MNS argues that their claims regarding a lower ELCC are exaggerated and inaccurate, and states that the BMPs mischaracterized Mr. Clark's testimony where he indicated that the ELCC "could" drop. MNS' reply brief, p. 15 (citing 5 Tr 1123) (emphasis omitted). Additionally, MNS notes that several witnesses refuted this argument, including Mr. Clark himself when he testified that the ELCC has been stable for six years and no changes are pending. MNS' reply brief, pp. 15-16 (citing 10 Tr 4226-4227, 4236). MNS observes that Mr. Blumenstock testified that even applying the BMPs' 30% ELCC figure, there would be no shortfall for eight years. MNS' reply brief, p. 16 (citing 10 Tr 4142-4143). Additionally, MNS notes, Mr. Jester showed that the BMPs' figure comes from an exploratory modeling exercise. MNS' reply brief, p. 16 (citing 10 Tr 4365-4366).

Finally, MNS objects to the BMPs' appeal of certain evidentiary rulings made by the ALJ, noting that the BMPs fail to cite to any legal authority in support of their appeal. MNS argues that a party may not "simply announce a position on appeal and leave it to the reviewing body to search for authority to support the party's position." MNS' reply brief, p. 18 (citing *Wilson v*

Taylor, 457 Mich 232, 243; 577 NW2d 100 (1998)). MNS contends that the BMPs' counsel misrepresented how long his cross-examination of Mr. Blumenstock would last, and then offered questions on irrelevant subjects. MNS' reply brief, p. 18 (citing 10 Tr 4193, 4211). MNS contends that, under MCL 24.280(1)(d), the presiding officer is empowered to regulate the course of the proceedings. MNS avers that the ALJ's rulings were reasonable and well within her authority and should be affirmed. MNS' reply brief, pp. 18-19.

In reply to Mackinac, MNS urges the Commission to give no weight to Mackinac's brief. As an initial matter, MNS alleges that Mackinac did not comply with the requirements of Rule 431(3) when it filed its objection, because it failed to state its objections with particularity or specify how it would be adversely affected by the settlement agreement. Additionally, MNS argues, Mackinac's initial brief is mostly cut-and-pasted from its exceptions, and the exceptions were focused on the PFD and the original PCA – a different factual scenario. MNS notes that Mackinac's initial brief is filled with unsupported assertions and relies heavily on news stories and website links that are not part of the record, contrary to the requirements of the APA. MNS' reply brief, pp. 20-21 (citing MCL 24.276 and 24.285). Moreover, MNS posits, DR and CVR programs are not designed to cut off customers from electricity. MNS describes Mackinac as "ill-informed." MNS' reply brief, pp. 21-22.

2. The Commission Staff

In reply, the Staff states that MCL 460.6t(8) provides seven factors for the Commission to balance when determining if the statutory requirements are satisfied. The Staff states that the settlement agreement is a compromise made by parties with a wide variety of interests and is reasonable and prudent. The Staff also contends that "the settlement agreement also balances the

reliability needs of MISO Zone 7 with Consumers' ability to provide energy and capacity to its customers." Staff's reply brief, p. 2 (citing Staff's initial brief, pp. 3-5).

Regarding resource adequacy concerns, the Staff replies that the PCA, as modified by the settlement agreement, is reasonable and prudent and balances the reliability needs of Zone 7. *See*, Staff's reply brief, p. 3. Continuing, the Staff avers that "[g]iven the capacity from Karn Units 3 and 4, additional solar resources, and the up to 700 MW one-time solicitation set forth in the settlement agreement, Staff . . . does not believe Consumers is likely to be short on capacity in 2025" and that "this capacity is more than sufficient to make up the capacity assumed for the CMS [plants] contemplated in Consumers' original IRP and may even be sufficient to meet Consumers' previous planning reserve margin of 8.7% that [WPSC] referenced in direct testimony." *Id*., pp. 3 4 (citing 10 Tr 4306, 4406-4407).

In response to the BMPs' testimony regarding a deficiency in 2035, the Staff replies:

> that the IRP statute requires 5-, 10-, and 15-year projections of the utility's load obligation and plan, but Commission cost approval for investments or resources used to meet energy and capacity need is only presumed reasonable and prudent for those actions commenced within three years of Commission approval of the IRP. MCL 460.6t(3), (11).

Staff's reply brief, p. 4. Therefore, the Staff avers that there is a likelihood that changes will occur between the approval of the IRP and the long-term projections as further reinforced by the requirement in MCL 460.6t(20) for regulated utilities make an IRP filing at least every 5 years. *Id*.

Finally, the Staff avers that Mackinac's "initial brief contains many footnotes citing to material that was not offered into evidence or addressed in testimony" and that Mackinac "did not file testimony in either phase of this proceeding and filed a one-page objection to the settlement agreement." *Id*., p. 6. Therefore, the Staff requests that the Commission disregard the portions of

Mackinac's briefing supporting its objections to the settlement agreement not supported on the record.

3. Environmental Law and Policy Center of the Midwest, Ecology Center, Inc., Union of Concerned Scientists, Inc., and Vote Solar

In reply to the BMPs, the CEOs point out that the BMPs' request to modify the settlement agreement is a form of relief that is unavailable because the settlement agreement is not severable, thus modification would result in rejection of the entire agreement. CEOs' reply brief, p. 1, n. 1. The CEOs further aver that the BMPs' contracts should not be extended in any case due to the non-carbon pollution associated with their operations as well as the documented environmental justice concerns. CEOs' reply brief, p. 2. The CEOs note that one of the directives issued by Governor Whitmer pursuant to ED 2020-10 requires the Michigan Department of Environment, Great Lakes, and Energy to include considerations of environmental justice and public health when issuing advisory opinions in IRP proceedings. *Id*., pp. 2-3. The CEOs submit that they provided extensive evidence on the record showing the non-carbon air pollution emissions and environmental justice concerns associated with the BMPs, stating that:

> [s]ome of these plants co-fire tire-derived fuels, and most of them have higher emission rates of $PM_{2.5}$ and NOx than even Consumers' coal plants. (Krieger, 7 TR 2383). Moreover, eight of nine plants are located in areas considered more low-income than the state median. (Krieger, 7 TR 2383). The 38,000 people living near the Genesee plant rank in the 89th percentile for low-income populations, 86th percentile for populations of color, and 83rd percentile on the EJ [Environmental Justice] Index. (Krieger, 7 TR 2384). "[B]iomass power plants are likely to have higher air pollutant emissions rates per unit energy produced."

CEOs' reply brief, p. 3 (quoting 7 Tr 2397) (emphasis omitted). The CEOs note that Dr. Bilsback concluded that the emissions rates of biomass plants are comparable to fossil-fuel fired plants. CEOs' reply brief, p. 4 (citing 7 Tr 2418). The CEOs contend that simply because a fuel source

may be renewable does not mean that it will not have health impacts; and they note that the BMPs did not rebut this testimony. CEOs' reply brief, p. 4.

The CEOs also regard the BMPs' argument that the settlement agreement is a ploy to allow for the construction of a natural gas plant as far-fetched. The CEOs point out that the settlement agreement (Section 6.b.ii.) limits the second tranche to "intermittent resources and dispatchable, nonintermittent clean capacity resources (including batter storage resources)," which could not be reasonably interpreted to include natural gas. *Id*. (quoting Settlement Agreement, p. 6). The CEOs further note that they would not be signatories to a settlement agreement that contemplates the construction of a new gas plant. CEOs' reply brief, p. 5 (citing 7 Tr 2354 and 10 Tr 4347). The CEOs contend that the land use concerns raised by the BMPs do not appear to relate to ED 2020-10. CEOs' reply brief, pp. 5-6.

The CEOs further argue that WPSC and the BMPs attempt to use scare tactics based on market information. The CEOs assert that Consumers used an appropriate capacity factor in its modeling, stating that, in reference to the BMPs' evidence, "[a]s Company witness Battaglia explained on rebuttal, the information shown in BMP-6 is presented in DC, rather than AC, and therefore does not present a comparable capacity factor to that used by the Company in modeling. (Battaglia Direct, 5 TR 1217:4-12)." CEOs' reply brief, p. 7. The CEOs also note that the BMPs focused on the wrong witness with respect to their ELCC arguments, as the solar capacity factor was covered by Mr. Kapala and not Mr. Battaglia (and this mistake was noted by the ALJ as well). *Id*., p. 8 (citing 6 Tr 1296-1297; 7 Tr 1822). The CEOs further assert that WPSC's theory that Consumers will be unable to acquire 250 ZRCs of solar by 2025 was refuted by Mr. Lucas. CEOs' reply brief, p. 9 (citing 10 Tr 4382-4384). They also cite to the testimony of Mr. Clark and Mr. Jester refuting the notion that the ELCC poses an unreasonable risk to the settlement

agreement. CEOs' reply brief, p. 9 (citing 10 Tr 4236, 4367-4368). Finally, the CEOs point to Mr. Blumenstock's testimony that Karn Units 3 and 4 are unlikely to become system support resources. CEOs' reply brief, p. 10 (citing 10 Tr 4152).

The CEOs assert that Mackinac's arguments are improper and redundant. CEOs' reply brief, p. 10.

4. Consumers Energy Company

Consumers initially provides an overview of the arguments of the signatories to the settlement agreement reiterating its position that the settlement agreement is in the public interest, was the result of good-faith negotiation, and that the outcome is the most reasonable and prudent means of meeting the company's energy and capacity needs. Consumers' reply brief, pp. 3-5.

Consumers argues that issues raised by WPSC with regard to reliability and resource adequacy concerns have been addressed by the company's initial brief. Specifically, Consumers states that "[WPSC]'s claim . . . that the one-time solicitation will likely not create new [MISO LRZ] 7 capacity, is of no consequence" for the reasons set forth in its initial brief. *Id*., p. 6. Consumers argues that "[t]he purpose of the one-time solicitation is to help replace the capacity and energy lost when Consumers Energy retires [Campbell] Units 1, 2, and 3 in 2025." *Id*. Consumers repeats that "[t]he Company is not required to provide capacity for [WPSC] or any other [LSEs] in LRZ 7." *Id*. Consumers states that WPSC's arguments that the settlement agreement will reduce reliability in LRZ 7 are "without merit" as outlined in its initial brief and WPSC has "failed to provide information showing any purported negative impact on [WPSC] . . . ." *Id*., p. 7. Consumers reiterates that the settlement agreement will "bring at least 2,084 ZRCs into MISO's LRZ 7 and retire only approximately 1,400 ZRCs of capacity, with a net addition for LRZ 7 of nearly 700 ZRCs." *Id*. (footnote omitted). In response to WPSC's claims that the company's

PRMR will increase rather than decrease, Consumers argues that it has "fully supported its projected PRMR decrease" in its initial brief. *Id*. Consumers argues that WPSC's claims that the one-time solicitation is "speculative and not supported by the record" are "meritless" and "Consumers Energy projects sufficient capacity for planning year 2025-2026, even without the additional 700 ZRCs of capacity proposed to be acquired via the solicitation, and many possible sources could fill the 700 ZRCs once the bidding commences." *Id*., p. 8 (quoting WPSC's initial brief, p. 9).

Consumers addresses WPSC's claim that the settlement agreement would "treat Consumers Energy as an 'island,' and that a capacity shortfall would affect [WPSC] and other LSEs in the state." Consumers reply brief, p. 8 (quoting WPSC's initial brief, p. 10). Consumers asserts that:

> Michigan law contemplates that each electric provider plan to serve its own projected loads; it does not require electric providers to serve other electric providers' loads, unless a utility is required to provide backup capacity under the state reliability mechanism in situations in which alternative electric suppliers fail to demonstrate compliance with their own four-year forward capacity obligations.

Consumers reply brief, p. 8 (citing MCL 460.6w). Consumers discredits WPSC's claims that the record does not support the settlement agreement. *See*, Consumers' reply brief, p. 9.

Turning to Energy Michigan's arguments, Consumers first agrees with Energy Michigan's contention that "the Commission Rule 431 standards for approving a contested settlement must harmonize with Section 6t(8) [of Act 341], and cannot overrule it or provide a 'different and weaker approval standard.'" Consumers reply brief, p. 9 (quoting Energy Michigan's initial brief, p. 2). Consumers posits that the settlement agreement "meets all criteria for approval contained in MCL 460.6t(8) and Commission Rule 431." Consumers reply brief, p. 9.

Consumers addresses Energy Michigan's assertion that company testimony stating "that 'Consumers Energy is not responsible to ensure the reliability of Zone 7 beyond its own capacity

obligations' indicates that the Company has changed its position, given that Mr. Clark described the IRP as the best plan 'for Michigan.'" *Id*., p. 10 (quoting Energy Michigan's initial brief, p. 3). Consumers asserts that it has not changed its position. Specifically, Consumers states that:

> The IRP, as set forth in the Settlement Agreement, remains the best plan for Michigan, as it will meet its customers' energy needs, will satisfy the Company's PRMR obligations within LRZ 7, and further the Company's goal to be carbon neutral by 2040 and retire all coal generation by 2025. Having the best plan for Michigan does not mean that Consumers Energy must single-handedly supply sufficient capacity for every other utility's expected load in Michigan. It means having a plan that meets all of Consumers Energy's customers' capacity needs in a manner that avoids unnecessary environmental impacts that affect the whole state and benefits the state's economy positively. An IRP that accomplishes these objectives is best for Michigan.

Consumers' reply brief, p. 10.

Consumers replies to Energy Michigan's claim that the one-time solicitation might ultimately lead to PPAs with CMS Enterprises. *Id*. Consumers responds that "[t]he Company has not yet issued the solicitation, thus Energy Michigan is merely speculating which resources will win." *Id*. Consumers avers that "even in the scenario that Energy Michigan envisions, no adverse impact on resource reliability or adequacy would result." *Id*.

Consumers refutes Energy Michigan's claim "that it was never invited to a settlement meeting, that its comments on the draft settlement agreement were neither welcomed nor considered," and that Energy Michigan was explicitly told that no changes it sent the company would be considered. *Id*., p. 11. Consumers posits that "[a] settlement meeting was held with all parties on February 16, 2022, and Energy Michigan's counsel participated in that meeting. Energy Michigan did not engage in settlement discussions after that meeting, even though such engagement was encouraged by the Company." *Id*. Further, Consumers states that "[b]eyond the February 16, 2022 settlement meeting, Energy Michigan was also engaged by the Company

regarding settlement on numerous occasions including March 28,2022, April 15, 2022, and April 19, 2022." *Id*., pp. 11-12.

Consumers avers that "Energy Michigan's assertions regarding the settlement process is irrelevant and beyond the scope of this case" as "other potential settlement outcomes are not within the scope of issues to be decided by the Commission in a contested settlement proceeding . . . ." *Id*., p. 12 (citing June 7, 2019 order in Case No. U-20165). Consumers also posits that the "[Commission]'s Rules of Practice and Procedure make clear that reaching a total consensus is not required for settlement." Consumers' reply brief, p. 12. Consumers adds that "Rule 431 makes clear that a settlement may be 'proposed by some of the parties." *Id*. (quoting Mich Admin Code, R 792.10431(3)). Further, Consumers quotes Rule 431 as stating that "'provisions of these rules shall not be construed in any way to prohibit settlements.'" Consumers' reply brief, pp. 12-13 (quoting Mich Admin Code, R 792.10431(3)).

Turning to the claims of the BMPs, Consumers argues that "even though the BMPs are claiming that the Settlement Agreement is flawed, they are at the same time conceding that all of those purported flaws melt away if the BMPs just get what they want—to amend the Settlement Agreement to force Consumers Energy to extend PPAs with its member plants." Consumers' reply brief, p. 14. Consumers posits that "[t]he BMPs' position illuminates the fact that there are not really flaws in the Settlement Agreement, as the BMPs' [sic] claim, and that the BMPs' position merely seeks to promote their own economic interests." *Id*. Further, Consumers avers that the BMPs have not established that their member plants are an economic and reasonable option for Consumers' customers following the expiration of the current PPAs for those plants. *Id*. Consumers further reiterates its positions from brief that the company does not have an obligation to enter into new contracts with the BMPs, that the BMPs were considered in the development of

the IRP, and that the BMPs have not produced evidence that they represent a viable economic option. *Id*. Consumers asserts that the BMPs' alterative proposal under Section 6t(6) of Act 341 is not supported because "the BMPs have failed to address and meet the filing requirements for an alternative proposal, as provided in the Certificate of Necessity and Integrated Resource Plan Alternative Filing Requirements." Consumers' reply brief, p. 15 (citing December 20, 2017 order in Case No. U-18461, Exhibit B). Consumers opines that the BMPs requested relief should be rejected because "[t]he BMPs have not established that their member plants will be an economic and reasonable resource option for customers and therefore, there is no basis to support the BMPs' request to force the Company to extend PPAs with those plants." Consumers' reply brief, p. 16.

In response to the BMPs' claims that the settlement agreement fails to meet the resource adequacy and reliability requirements of Sections 6t(8)(a)(i) and (iv) of Act 341, Consumers asserts that "[t]he Settlement Agreement ensures resource adequacy and capacity that is sufficient in quantity to serve anticipated peak electric load plus applicable PRMR and Local Clearing Requirement . . . ." Consumers' reply brief, p. 17. Consumers argues that the settlement agreement has "maintained a balance of resource additions and retirements—backfilling capacity lost to accelerated retirement with the addition of new baseload resources, expansion of demand-response resources, expansion of renewable resources, and deployment of battery storage resources." *Id*. (citing 10 Tr 4121). Consumers also reiterated that the settlement agreement provides mechanisms to procure additional capacity if needed. Consumers' reply brief, p. 17. Consumers posits that the settlement agreement provides for "electric reliability assurance" and that the "flexibility of phased-in modular resources provided for in the Settlement Agreement PCA also provides the Company adequate time to mitigate cost, assess reliability within the reconfigured portfolio, and to modify as necessary." *Id*., p. 18.

Consumers contests the BMPs' claim that the company used an incorrect capacity accreditation for its solar resources. Consumers restates that the company's PCA "uses the current MISO solar capacity accreditation practices which provide solar with a 50% capacity accreditation." *Id*. (citing 10 Tr 4142). Consumers reiterates its arguments that "that MISO solar capacity accreditation value is also only relevant to newly installed solar and not solar that is in actual operation. Capacity accreditation at the Company's existing solar facilities has been as high as 65%, based on actual performance." Consumers' reply brief, p. 19 (citing 10 Tr 4142). Consumers argues that the company has supported its modeled capacity factor for solar with projections from third-party resources. Consumers' reply brief, p. 19. Thus, Consumers opines that the BMPs' resource adequacy and reliability arguments should be rejected. *Id*.

Responding to the BMPs' claims that the settlement agreement fails to meet the requirements of Section 6t(8)(b) of Act 341 and Governor Gretchen Whitmer's MI Healthy Climate Plan pursuant to ED 2020-10, Consumers argues that "the record establishes that the Settlement Agreement is aligned with that plan, and will help promote its success." Consumers' reply brief, p. 20. Consumers adds that to the extent the BMPs are arguing that additional imports from the market violate ED 2020-10, the PCA, as modified by the settlement agreement, "reduced the need for market purchases" and "continues to maintain that reduced market dependence through the purchase of the Covert Plant and one-time solicitation . . . ." *Id.*

Addressing the BMPs' assertion that Karn Units 3 and 4 could be designated as an SSR, Consumers reiterates that "an SSR designation would result from an electric transmission system deficiency that must be mitigated and not due to a capacity or energy shortfall." *Id*., p. 21. Reiterating its earlier testimony, Consumers argues that the risk of an SSR designation is unsupported. *Id*., pp. 20-21.

In response to the BMPs' assertion that the settlement agreement fails to appropriately balance the diversity of generation resources with the impacts on commodity price risk, Consumers asserts that the settlement agreement provides for a diverse portfolio of resources as outlined in its testimony. *Id*., p. 21. Consumers posits that "[t]his resource mix represents a balanced and modular supply plan which provides flexibility to adjust to changes in fuel costs, technology cost, electric demand, or the business environment and insulates the Company and its customers from commodity price risks." *Id*. Further, Consumers asserts that this approach will "provide further opportunities for the utilization of diverse supply resources and protects against high customer rates." *Id*.

Consumers reiterates its arguments, outlined above, regarding the scope of the contested settlement agreement in response to the BMPs. *See*, *id*., pp. 23-26. Consumers reasserts that the BMPs attempt to propose another version of the settlement agreement is "improper and not supported." Consumers' reply brief, p. 25. On pages 26 through 33 of its reply brief, Consumers addresses the BMPs' appeal of the ALJ's rulings.

Consumers asserts that Mackinac's objections to the settlement failed to comport with the Commission's procedural rules and should thus be disregarded. *Id*., pp. 32-33.

Consumers requests the Commission approve the settlement agreement in its entirety without any modifications or conditions. *Id*., p. 33.

5. Wolverine Power Supply Cooperative

WPSC argues that the settlement agreement "has neither the facts nor the law on its side and the Commission must reject it." WPSC's reply brief, p. 1. WPSC contends that the Staff has reversed its stance on the importance of resource adequacy as the Staff now contends that the settlement agreement "should be approved because Zonal resource adequacy is not Consumers'

problem to solve." WPSC's reply brief, p. 3 (citing Staff's initial brief, p. 5). WPSC avers that while it is not the sole responsibility of Consumers to "ensure resource adequacy for the Zone, a significant component of the IRP framework is to ensure that a utility retiring resources does not do so in a manner that adversely impacts the Zone, which Consumers does here" and that "although Consumers may not be required to address a shortfall caused by others, it certainly must be required to address a shortfall it is creating." *Id*. (emphasis omitted).

WPSC again avers that the settlement agreement is not supported by substantial evidence and that the company has not disputed the negative ZRC values for 2022-2023 and 2025-2026. *See*, *id*., p. 4. WPSC reiterates concerns regarding the ELCC for solar assets, arguing that the 50% is not an accurate benchmark as "[i]t simply does not reflect reality, even if some are willing to pretend that it does." *Id*. WPSC further states that it has "identified actual impediments to Consumers' contemplated solar development and Consumers offered no explanation as to how it will overcome these hurdles, except to say there is time to address in future IRPs. [WPSC] identified the issues; Consumers identified no solutions." *Id*., p. 5.

Finally, WPSC argues that the Staff's briefing lacks confidence "[m]uch like Consumers' failure to explain its solution to the hurdles related to solar development, Staff appears to be counting on speculative 'other resources' that are not identified in brief or the record." *Id*. Therefore, WPSC avers that the settlement agreement is speculative and should be denied under Rule 431(5).

6. The Biomass Merchant Plants

In reply to Consumers, the BMPs reference their initial brief to respond to the claim that the BMPs' "requested relief is beyond the scope of these proceedings" averring that "[i]t is not." BMPs' reply brief, p. 2. The BMPs reiterate that while "PURPA may no longer require

Consumers to purchase generation from the Biomass Plants [that] does not mean that such purchases are not reasonable and prudent as a matter of state law" and that Consumers has done everything possible "to exclude the Biomass Plants from the IRP, regardless of whether or not including them would be reasonable and prudent." *Id*. (citing to BMPs' initial brief, p. 29-38). Reiterating the testimony and briefing, the BMPs state that the company never requested cost information from the BMPs and failed to explain why the cost of new construction was utilized for biomass generation. *See*, BMPs' reply brief, pp. 2-4.

Responding to Consumers' contention that the BMPs would be eligible to bid into the first tranche of the one-time solicitation, the BMPs aver that:

> [w]hile the Biomass Plants can be dispatched within their operational limits, they cannot be dispatched within one hour if they are not running. That fact, in addition to the fact that all of the Biomass Plants' current contracts extend into the 2025 to 2030 time period will exclude them from bidding in that solicitation.

Id., p. 4 (referencing Consumers' initial brief, p. 45). The BMPs again reference objections and excluded evidence which they aver were inappropriately ruled upon by the ALJ. The BMPs aver that Consumers failed to discuss "whether [Consumers] is likely to sign power purchase agreements with [the CMS plants] as a result of the first tranche of the One Time Solicitation, which is probable." *Id*., pp. 5-6. Further, the BMPs restate record testimony to aver that Consumers has still failed to rebut the BMPs' testimony regarding the overstated solar capacity factor the company has utilized, and the risk associated with proposed solar additions. *See*, *id*., pp. 6-10. The BMPs argue that Consumers' dismissal of the risks relating to the solar additions, and "its refusal to add the 188 MW of baseload, net zero carbon, renewable generation from the Biomass Plants to its IRP" are invalid and raise "serious questions as to whether the Biomass Plants are being excluded from the IRP for some other undisclosed commercial reason." *Id*., pp. 10-11.

V. Discussion

The Commission finds that the contested settlement agreement at issue in this case should be approved.

As stated above, Commission approval of a contested settlement agreement is appropriate where the Commission determines the following requirements have been met: (1) that the objecting parties have been given a reasonable opportunity to present evidence and arguments in opposition to the settlement agreement, (2) the public interest is adequately represented by the parties who entered into the settlement agreement, (3) the settlement agreement is in the public interest, (4) the settlement agreement represents a fair and reasonable resolution of the proceeding, and (5) the settlement agreement is supported by substantial evidence on the record as a whole. Mich Admin Code, R 792.10431.

The Commission finds that all the requirements of Rule 431 have been met. The Commission has provided a reasonable opportunity to those parties that objected to the settlement agreement to present evidence and argument in opposition to the settlement agreement. The parties were given the opportunity to submit direct and rebuttal testimony, file initial and reply briefs, and appear at an evidentiary hearing regarding the contested settlement agreement before a presiding officer. As the parties to this case observed, the principal record in this case consists of 4,094 pages of transcript and over 500 exhibits admitted into evidence. The record on the contested settlement alone consists of 315 additional pages of transcript and 22 additional exhibits admitted into evidence.

With respect to the second criterion, the record shows that the signatories to the settlement agreement represent a broad cross-section of interests, including residential customers, commercial and industrial customers, businesses in Michigan's advanced energy sector, environmental groups,

a transmission company, and third-party developers. *See*, 10 Tr 4407-4408. The Commission also notes that the Court of Appeals has affirmed the Commission's determination that the public interest is adequately represented by the Staff when the Staff is party to a contested settlement agreement. *Attorney General v Mich Pub Serv Comm*, 237 Mich App 82, 93-94; 602 NW2d 225 (1999). Accordingly, the Commission finds that the public interest is adequately represented by the parties who entered into the settlement agreement.

Rule 431(5)(c) requires the Commission to make a three-part finding that: (1) the settlement agreement is in the public interest, (2) represents a fair and reasonable resolution of the proceeding, and (3) is supported by substantial evidence on the record as a whole.

The Commission finds that the settlement agreement is in the public interest. The Commission finds persuasive the testimony by Consumers and others that the settlement agreement was the result of good-faith negotiation that resulted in significant compromises for all involved. The negotiation of the parties is evident when comparing the details of Consumers' initial IRP filing with the terms of the proposed settlement agreement. Signatory parties to this case highlighted the following provisions as compromises reached by settlement that are in the public interest, represent a fair and reasonable resolution of the proceeding, and are supported by substantial evidence on the record as a whole:

- The agreement that Consumers retire Campbell Units 1, 2, and 3 in 2025, which will result in savings to ratepayers, reduce the production of environmental pollutants, such as SO_2, NO_x, and particulate matter, and advance Michigan's clean energy goals as outlined in the MI Healthy Climate Plan as well as provide additional public health benefits;

- The agreement that Consumers will purchase the Covert plant in 2023, which will add 1,114 ZRCs to MISO Zone 7 to support reliability for Consumers as well as overall resource adequacy of the Zone;
- The agreement to conduct a one-time solicitation for 200 ZRCs of capacity and associated energy and RECs, which will provide additional clean capacity resources for Consumers' portfolio;
- The agreement that Consumers will deploy the battery program outlined in the rebuttal testimony in the principal case which will formalize an important component of a cleaner energy grid while enhancing reliability and resource adequacy;
- The agreement to seek recovery of the unrecovered book value and decommissioning costs of retiring coal units through regulatory asset treatment, rather than continued recovery through traditional ratemaking, which provides the potential for customer savings;
- The agreement that Consumers will donate $5 million dollars in shareholder funds to support bill assistance for lower-income customers along with continued annual donations;
- The agreement that Consumers will provide beneficial modeling in its next IRP, including total emissions, annual particulate matter health impacts, an environmental justice screening tool, projected low-income energy efficiency participation levels, publicly available rooftop solar adoption rates, and transmission import analysis; and
- The agreement that Consumers will take steps to engage and gather input from the public prior to the filing of its next IRP with the Commission, which will ensure that additional information and perspectives are available to inform both the company's assessment of its future resource options as well as Commission and stakeholder review of its proposals.

Energy Michigan, WPSC, the BMPs, and Mackinac disagree with the conclusion that the settlement is in the public interest and represents a reasonable resolution to the proceeding. The objecting parties' concerns involve the resource adequacy, reliability, and competitive pricing in MISO Zone 7. Specifically, the objecting parties argue that: (1) the settlement agreement does not meet the resource adequacy needs of MISO Zone 7 and (2) the one-time competitive solicitation will not adequately replace the capacity from retiring coal-fired generation. Each of these concerns are addressed in turn.

A. The Resource Adequacy of Zone 7

The parties objecting to the settlement agreement claim that the settlement agreement does not address the need for incremental capacity replacements in MISO Zone 7 following the retirement of Campbell Units 1, 2, and 3 to meet the resource adequacy requirements of the zone. As such, the objecting parties conclude that Consumers' PCA fails to meet the resource adequacy requirements of Section 6t(8)(a)(i) and (iv) that the Commission must balance "[r]esource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement" and "reliability" to determine that the integrated resource plan is the most reasonable and prudent means of meeting energy and capacity needs. The Commission disagrees.

The Commission finds the testimony of the Staff, MNS, and Consumers compelling. As Consumers testifies, the settlement agreement continues the annual solicitation process adopted by the company in its 2018 IRP. 10 Tr 4121. By preserving the solar ramp-up proposed in the original PCA, the settlement agreement adds 250 ZRCs of new solar generation by the 2025/2026 PY, increasing to 852 ZRCs by the 2028/2029 PY. 10 Tr 4350. The settlement agreement provides that Consumers will deploy a new utility-scale battery storage program which will add

approximately 71 ZRCs of new capacity to the zone. 10 Tr 4350. Finally, preserving the EWR and DR provisions from Consumers' original PCA, the settlement provides 94 ZRCs of demand-side resources by the 2025/2026 PY, increasing to 2031 ZRCs by the 2028/2029 PY. The settlement also provides for increases in both the demand-side resources and solar resources in later years. 10 Tr 4350.

In addition to these new resources, the settlement agreement provides for the acquisition of the Covert plant, which will transfer approximately 1,114 ZRCs from PJM into MISO Zone 7. 10 Tr 4123, 4225, 4230, 4331. The settlement agreement has the effect of adding approximately 770 ZRCs through the continued operation of Karn Units 3 and 4 until May 31, 2031, consistent with the design lives of those units. 10 Tr 4225, 4334.

MNS provides that "the settlement [agreement] will result in a projected net increase of at least 127 ZRCs. By 2028/29, the projected net increase will be at least 923 ZRCs." 10 Tr 4350. The Staff further contends that, "[t]he Company was originally proposing to retire approximately 2800 MW (nameplate) generation from MISO Zone 7 . . . ," meanwhile the settlement agreement "only retires a portion of that amount, approximately 1500 MW . . . ." 10 Tr 4405. The projections by both MNS and the Staff are in addition to any resources that may be acquired through the one-time solicitation, discussed below. 10 Tr 4351-4352, 4406. As Consumers observes, the settlement agreement provides for more capacity in Zone 7 than was included in the company's originally filed PCA. 10 Tr 4230. The Commission thus finds that the settlement agreement provides a reasonable and prudent plan for meeting resource adequacy requirements.

The Commission acknowledges the larger resource adequacy concerns of the objecting parties as valid and timely. The broader resource adequacy of Zone 7 and the MISO region has an impact on both Consumers' customers and the state as a whole. The Commission observes that the

2022/2023 MISO PRA results indicate a capacity shortfall for the MISO North and Central Regions.[5] These auction results indicate that many LSEs in MISO will experience a greater risk of implementing involuntary conservation measures even though many of them would appear to be resource adequate when viewed as a stand-alone entity. While the market construct within MISO allows for the pooling of resources to lower the total cost to customers, this market construct means that the planned retirements and resource decisions of one utility impact the customers of other utilities within the Zone and the greater regional transmission organization (RTO).

While the Commission agrees with Consumers' assertion that the company is not responsible for the reliability of the entirety of MISO Zone 7, it is also clear that a deficiency in any part of Zone 7 would increase the likelihood of grid outages for all customers in Zone 7, including those served by Consumers.

As noted above, however, the approval of the settlement agreement enhances zonal resource adequacy in the short, medium, and long term(s). In the short term, the acquisition of the Covert plant will transfer approximately 1,114 ZRCs from PJM into MISO, providing much needed additional capacity to LRZ 7 for the next MISO PY. In the long term, as noted by Mr. Jester, "[c]ontinuing to operate Karn 3-4 supports Consumers' attainment of planning reserve margin requirements by maintaining more than 780 ZRCs in the Company's portfolio." 10 Tr 4334. And as the Staff noted, the settlement agreement represents "a resource adequacy improvement over the Company's original PCA[,]" and provides for approximately 400 ZRCs of new resources within

[5] The resources in the MISO region operate as a shared pool of resources to meet the PRMR. As demonstrated in the MISO 2022/2023 PRA results, capacity shortfalls in four MISO Zones resulted in the entirety of the MISO North/Central Regions having a slightly increased risk of needing to implement temporary controlled load sheds. The 2022/2023 PRA results are available at: https://cdn.misoenergy.org/2022%20PRA%20Results624053.pdf (accessed, June 17, 2022).

MISO Zone 7 by 2025, in addition to the one-time solicitation for 700 MW set forth in the settlement agreement. 10 Tr 4405, 4406. Finally, while acknowledging the challenges to resource adequacy that were highlighted in MISO's recent PRA results, the Commission notes Consumers' testimony that it "will file at least one, if not multiple, IRPs" between now and when any projected shortfalls are likely to occur, and that it will have "ample time to respond and adjust the PCA" if necessary. 10 Tr 4143-4144. As such, the Commission is satisfied that the approval of the settlement agreement will enhance resource adequacy in Zone 7 in both the near-term and long-term.

In order to ensure future IRPs appropriately consider zonal resource adequacy in addition to the resource requirements of a particular utility, the Commission directs the Staff to include a requirement for each utility to consider the impacts of its PCA on the resource adequacy of its own customers, the LRZ in MISO or its equivalent in PJM, and also assess the potential impacts, if any, of its decisions on customers in neighboring Zones, regions, or RTOs in the upcoming IRP filing requirements update in Case No. U-18461 in order to better enable the Commission to determine whether future PCAs meet resource adequacy needs of the LRZ.

B. The One-Time Solicitation

The parties objecting to the settlement agreement also express concerns regarding the one-time solicitation as it is outlined in the settlement agreement. Among the concerns, Energy Michigan asserts that the 500 ZRC capacity need that Consumers is seeking to fill through the first tranche of the one-time solicitation will result in capacity that is not additional to what is already being counted toward MISO Zone 7's resource adequacy requirements. 10 Tr 4297. The BMPs and WPSC express concerns that the timing and framing of the one-time solicitation will not result in new resources being added to the market. Specifically, these two parties assert that it will not

be possible for new generation to obtain a MISO Interconnection Services Agreement, complete project engineering, obtain financing, and construct a new plant by 2025, as the settlement agreement requires the generation to provide Consumers with a capacity credit in MISO Zone 7 by 2025. The Commission finds that this reasoning for denying the settlement agreement is speculative. As several parties contended, the terms of the settlement agreement require that the resources acquired be competitively sourced. The Commission finds persuasive testimony that "respondents to the solicitation could be from some of the projects currently in the MISO queue . . . that makes up nearly 1,800 MW of projects that are currently in Study Phase 2 or 3." 10 Tr 4404 (footnote omitted). And further that "there are more than 13,011 MWs of solar, battery, and solar/battery hybrid projects located in MISO Zone 7 that have an application in-service date by or before June 1, 2025 . . . . Of these projects, 5,365 MW of solar, 499 MW of solar/battery hybrid, and 370 MW of battery have completed Phase 2 or Phase 3 interconnection studies and are therefore highly likely to proceed if the developer has an offtake or build-transfer agreement." 10 Tr 4363-4364 (footnotes omitted). The Commission finds that the one-time solicitation is in the public interest as it is likely to contribute to—or at a minimum not be detrimental to—the overall resource adequacy of MISO Zone 7.

However, to clarify, the Commission does not interpret the language of the settlement agreement to mean that it is pre-judging any approval requests it may receive from Consumers as a result of this one-time solicitation or any other approval requests that Consumers may file following the implementation of its PCA. The language of the settlement reads:

> [T]he actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;
>
> > In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery

> of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated 7 with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

Settlement Agreement, pp. 6-7. As such, the Commission will examine the results of the one-time solicitation carefully and will scrutinize any effects it may have on resource adequacy and competitive pricing in Zone 7.

Having addressed each of the arguments as to whether the settlement agreement is in the public interest and represents a fair and reasonable resolution of the proceeding, the Commission finds that, for all the reasons set forth, the settlement agreement is in the public interest. The Commission also finds that the proposed settlement agreement is a fair and reasonable resolution of this proceeding. In addition, having read the record, the Commission likewise finds the settlement agreement to be supported by substantial evidence on the record as a whole. Moreover, as agreed to by the parties in paragraph 1 of the settlement agreement and supported by the record, the Commission finds that Consumers' PCA as amended by the settlement agreement is the most reasonable and prudent means of meeting Consumers' energy and capacity needs and otherwise meets the requirements of MCL 460.6t(8).

THEREFORE, IT IS ORDERED that:

A. The settlement agreement, attached as Exhibit A, is approved.

B. Unless otherwise provided in the settlement agreement, the terms of the approved settlement agreement shall take effect immediately upon issuance of this order.

C. The Commission Staff shall include a requirement for each affected utility to consider the impacts of its proposed course of action on the resource adequacy of its own customers, the Midcontinent Independent System Operator, Inc. Local Resource Zone or respective PJM

Interconnection, L.L.C. Zone, and neighboring Zones, regions, or regional transmission organizations in the updated integrated resource plan filing requirements to be filed on June 30, 2022, in Case No. U-18461, as outlined in this order.

D. In accordance with paragraph 11(g) of the settlement agreement, Consumers Energy Company shall file, within 30 days of this order, revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of the approved settlement agreement. Also pursuant to paragraph 11(g), parties shall have 14 calendar days subsequent to these filings to provide comments to the Commission in this docket.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General – Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General – Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Tremaine L. Phillips, Commissioner

By its action of June 23, 2022.

Lisa Felice, Executive Secretary

EXHIBIT A

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

SETTLEMENT AGREEMENT

Pursuant to MCL 24.278 and Rule 431 of the Michigan Administrative Hearing System's Rules of Practice and Procedure before the Michigan Public Service Commission ("MPSC" or the "Commission"), the undersigned parties agree as follows:

WHEREAS, on June 30, 2021 Consumers Energy Company ("Consumers Energy" or the "Company") filed an Application requesting approval of the Company's Integrated Resource Plan ("IRP") pursuant to Section 6t of 2016 PA 341, MCL 460.6t, the Commission's June 7, 2019 Order Approving Settlement Agreement in Case No. U-20165, and all other orders and applicable law. The Company filed testimony and exhibits in support of its positions concurrently with its Application.

WHEREAS, the initial prehearing conference was held on July 22, 2021 before Administrative Law Judge ("ALJ") Sally L. Wallace. Beyond the Company, the parties to the IRP are: the MPSC Staff ("Staff"); the Attorney General; Hemlock Semiconductor Operations, LLC ("HSC"); the Biomass Merchant Plants ("BMPs")[1]; Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club ("MNS"); Great Lakes Renewable Energy

[1] The BMPs consist of: Cadillac Renewable Energy, LLC, Genesee Power Partners Limited Partnership, Decker Energy-Grayling, LLC, Hillman Power Company, LLC, Tondu Corporation, National Energy of Lincoln, LLC, f/k/a Viking Energy of Lincoln, LP and National Energy of McBain, f/k/a Viking Energy of McBain, LLC.

Association ("GLREA"), Environmental Law and Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists (collectively, the Clean Energy Organizations ("CEO")); Residential Customer Group ("RCG"); Association of Businesses Advocating Tariff Equity ("ABATE"); Michigan Energy Innovation Business Council, Institute for Energy Innovation, and the Clean Grid Alliance (collectively, "Michigan EIBC/IEI/CGA"); Energy Michigan, Inc. ("Energy Michigan"); Midland Cogeneration Venture Limited Partnership ("MCV"); Michigan Electric Transmission Company, LLC ("METC"); Michigan Public Power Agency ("MPPA"); Wolverine Power Supply Cooperative ("Wolverine"); the Citizens Utility Board ("CUB"); the Mackinac Center for Public Policy ("Mackinac"); and the Urban Core Collective ("UCC"). 1 TR 11-12, 22.

WHEREAS, Consumers Energy filed testimony and exhibits requesting approval of the Company's IRP Proposed Course of Action ("PCA") in its entirety, as the most reasonable and prudent means of meeting the Company's energy and capacity needs through 2040. The Company specifically requested the Commission to make the following determinations:

(i.) Approve Consumers Energy's PCA, which is inclusive of all proposals presented by the Company in this case, including the battery deployment program, as the most reasonable and prudent means of meeting the energy and capacity needs of the Company and its customers;

(ii.) Approve the Company's acquisition and proposed purchase costs for the New Covert Generating Facility ("Covert Plant") and Dearborn Industrial Generation ("DIG Plant"), the Livingston Generating Station ("Livingston Plant"), and the Kalamazoo River Generating Station ("Kalamazoo Plant"), in the manner proposed by the Company, and proposed Energy Waste Reduction ("EWR"), Demand Response ("DR"), and Conservation Voltage Reduction ("CVR") costs which will be commenced by the Company within three years following the Commission's expected approval of the Company's IRP;

(iii.) Approval of the selection and proposed purchase of the DIG, Kalamazoo, and Livingston plants, by the Company from its affiliate, CMS Enterprises. The transaction was a result of a competitive solicitation and is compliant with the Commission's Code of Conduct requirements. In the alternative, while complying with all other provisions of the Code of Conduct, the Company

requests a waiver of the asset transfer provision of the Code of Conduct, Mich Admin Code R 460.10108(4), for the acquisition of the DIG, Livingston, and Kalamazoo plants, from CMS Enterprises;

(iv.) Approve the Company's proposal to recover the unrecovered book balances of D.E. Karn ("Karn") Units 3 and 4 and J.H. Campbell ("Campbell") Units 1, 2, and 3, including decommissioning costs, through regulatory asset treatment, with full return, over the design lives of those units;

(v.) Approve the Company's proposals to: (i) defer employee retention costs related to the proposed accelerated retirements of Karn Units 3 and 4 and Campbell Units 1, 2, and 3, and (ii) defer retirement transition costs for future recovery;

(vi.) Approve the Company's proposed modifications to its Public Utility Regulatory Policies Act of 1978 ("PURPA") construct and the Company's proposed competitive procurement process and the use of that competitive procurement process for: (i) determining PURPA avoided costs rates, and (ii) determining and addressing the Company's capacity position under PURPA;

(vii.) Determine that the Company has no PURPA capacity need so long as the Company is implementing the PCA, with the competitive procurement process proposed by the Company; and

(viii.) Approve the Company's proposed Financial Compensation Mechanism ("FCM") for any new, or newly amended, Power Purchase Agreements ("PPAs") entered into by the Company.

Staff and other intervening parties filed testimony and exhibits addressing various issues.

NOW THEREFORE, for purposes of settlement of Case No. U-21090, the undersigned parties agree as follows:

1. The parties agree that the Company's PCA, as modified in this Settlement Agreement, should be approved as the most reasonable and prudent means of meeting the Company's energy and capacity needs over the 5-year, 10-year, and 15-year time horizons. The parties agree that the Company will file its next IRP consistent with the requirements of MCL 460.6t.

2. The parties agree that the PCA shall include the Company's proposed purchase of the Covert Plant in 2023 but shall not include the ownership of the DIG, Kalamazoo, and

Livingston plants. The parties agree that the identified capital costs that the Company will incur for DR ($23,751,000), CVR ($9,736,315), and the purchase of the Covert Plant ($815 million) in the next three years (June 2022 – June 2025) are reasonable and prudent and approved for cost recovery purposes and will be included in rates in a future Company rate case consistent with MCL 460.6t(11) and (17). The parties further agree to the approval of the projected capacity value provided by the Covert Plant and the DR (projected to achieve a total of 641 MW (657 Zonal Resource Credits ("ZRCs")) by 2025), CVR (projected to achieve 136,351 MWh savings by 2025, 56.81 MW savings by 2025), and EWR (projected to achieve 545,305 MWh savings in 2025, 879 MW savings by 2025) resources included in the PCA during the next three years. The parties further agree that the Company shall continue to file an annual reporting template with the Commission addressing the implementation of the approved DR and CVR resources above.

3. The parties agree to the approval of the battery deployment program as proposed by Company witness Richard T. Blumenstock. The parties agree that the Company will conduct stakeholder outreach to solicit feedback regarding the battery deployment program prior to the issuance of the first battery deployment program competitive solicitation. The approval to recover the costs associated with the batteries acquired in the battery deployment program will be sought in future electric rate cases.

4. The parties agree that (i) Karn Units 3 and 4 will be retired on or before May 31, 2031, absent extraordinary circumstances that require prolonged operation, such as a System Support Resource designation by Midcontinent Independent System Operator, Inc. ("MISO") or other emergent issues within the Company's generation portfolio which require continued

operation of Karn Units 3 and 4 to maintain sufficient supply; and (ii) Campbell Units 1, 2, and 3 will be retired on or before May 31, 2025.

5. The parties agree that the Company will not file an application for a financing order for the unrecovered book balance and decommissioning costs of Campbell Units 1, 2, and 3. The parties agree that the Commission will permit Consumers Energy to recover the unrecovered book balance of Campbell Units 1, 2, and 3 through the Company's proposed regulatory asset treatment, with a return equal to the Company's weighted average cost of capital ("WACC") premised on the return on equity approved by the Commission in rate cases prior to the retirement date of those units and a 9.0% return on equity after the retirement date of those units, as part of the Company's electric rates over the current design lives of those units. The 9.0% return on equity will be used to modify the capital structure filed with each rate case and the return on equity will be the only modification to the capital structure used to calculate the return on the regulatory asset after the retirement date of the units. The parties further agree that the Company will be permitted to record a regulatory asset for actual decommissioning spending for Campbell Units 1, 2, and 3, with a return on the regulatory asset, with subsequent rate recovery in a rate case after a review of the reasonableness and prudence of the expenses. Recovery of the associated decommissioning and ash disposal costs will be treated as follows:

a. The decommissioning costs, less salvage value, related to Campbell Units 1, 2, and 3 and the ash disposal costs related to Campbell Units 1, 2, and 3 will be recorded, as spent, to a regulatory asset; and

b. The Company may request recovery in future base rate proceedings, and upon Commission determination that the Company has incurred those costs as the result of reasonable and prudent actions, they shall be included in rates. The Company will ensure that the amounts recovered through a regulatory asset account are net of any accumulated depreciation amounts.

6. The parties agree that subsequent to the Commission's order approving this Settlement Agreement, the Company shall issue a competitive solicitation ("the One-Time Solicitation") which will include the following parameters:

a. The One-Time Solicitation will seek projects which will provide the Company with capacity credit in the MISO Zone 7 starting in the 2025 Planning Year;

b. The One-Time Solicitation will include two all source tranches:

i. The first tranche will seek up to 500 ZRCs of capacity and associated energy and renewable energy credits ("RECs"), if applicable, from PPAs with terms up to 10 years. This tranche will seek dispatchable, non-intermittent generation capable of dispatching up or down in every hour of the year in response to wholesale energy market signals, providing capacity which meets the Local Clearing Requirement of MISO Zone 7; and

ii. The second tranche will seek up to 200 ZRCs of capacity and associated energy and RECs, if applicable, secured from unaffiliated third parties via PPAs or other third-party agreements that do not result in Company ownership with terms up to 25 years, at the discretion of the bidder. This tranche will seek intermittent resources and dispatchable, non-intermittent clean capacity resources (including battery storage resources), providing capacity which meets the Local Clearing Requirement of MISO Zone 7. This tranche will furthermore take into consideration the ability of the offered capacity to meet the Local Clearing Requirement of MISO Zone 7 for the duration of the contract length. Prior to the issuance of the second tranche portion of the One-Time Solicitation, the Company shall hold a stakeholder meeting including parties to this case and energy storage developers to discuss methods to improve RFPs and response to solicitations with respect to stand-alone storage projects and hybrid-storage projects.

c. The Company's acquisition of the 700 ZRCs and associated energy and RECs, if applicable, sought in the One-Time Solicitation shall be considered incorporated into the PCA approved in Paragraph 1 of this Settlement Agreement. However, the actual selected bid(s) will be submitted in Case No. U-21090 for Commission approval subsequent to the completion of the One-Time Solicitation;

i. In that approval proceeding, the Commission shall: (i) confirm whether the solicitation process followed by the Company is consistent with the requirements of the Settlement Agreement; (ii) grant approval of the recovery of the costs associated with the selected project(s) pursuant to applicable law or make a preliminary finding that the costs associated

with the project(s) that prevail in the solicitation are reasonable and prudent; and (iii) grant any other approvals or findings necessary as required or provided by applicable law.

d. The One-Time Solicitation will not be used to set the Company's avoided costs rates or capacity needs under PURPA.

7. The parties agree to the approval of the Company's proposed accounting request to defer expense related to the Campbell site severance and retention agreement, utilizing a regulatory asset to record the deferred amounts. The deferred amounts for 2022 will be capped at $26 million. All amounts deferred for 2022 and beyond will be reviewed in future rate cases. This Settlement Agreement does not permit the Company to defer amounts related to the Campbell site severance and retention agreement outside of 2022.

a. Consumers Energy will publicly file in Case No. U-21090 its community transition plan for Karn Units 1 through 4 within 150 days of all four Karn Units ceasing operation; and

b. Consumers Energy will develop a draft community transition plan for the Campbell site. During the development of this draft community transition plan for the Campbell site, Consumers Energy will consult with community-based organizations and community members living in the area surrounding the retired assets on the community transition plan before finalizing and filing it for informational purposes in Case No. U-21090.

8. The parties agree to the extension of the annual competitive bidding process used to acquire the supply-side resource technologies specified in the PCA, as approved in Case No. U-20165 (collectively the "Annual Solicitations" and individually an "Annual Solicitation"), with certain modifications included below:

a. Qualifying Facilities ("QFs") that the Company has a legal obligation to purchase from under PURPA (such facilities are referred to as "QFs" in this Settlement Agreement), may bid any technology into the Annual Solicitation but will be required to submit an offer consistent with the PPA terms sought in the Annual Solicitation;

b. The competitive bid process shall be administered by an independent third party. The evaluation criteria and process is to be made available to all bidders submitting responses for the specific technology requested by the

Company, as part of the RFP, to ensure transparency. QFs may bid any technology that meets the requirements of PURPA. A ranking of proposals is to be used by the independent third party and provided to the Company for selection;

c. In its September 9, 2021 Order in Case No. U-20852 the Commission adopted competitive bidding guidelines titled "Competitive Procurement Guidelines for Rate-Regulated Electric Utilities (Not for PUPRA Compliance) and "Competitive Procurement Guidelines For Rate-Regulated Electric Utilities for PURPA Avoided Cost and Capacity Determination." The "Objective" of the adopted guidelines provides that when the guidelines are utilized by utilities, it is presumed that resulting projects and contracts are reasonable and prudent and in the event utilities diverge from the guidance provided in the guidelines, it is expected that the utility will provide sufficient justification in order to receive Commission approval and recovery. In the Annual Solicitation process, the Company will follow the Commission's adopted guidelines, including the ability to diverge from the guidance as provided in the guidelines;

d. The first competitive solicitation for the Company pursuant to this Settlement Agreement will be conducted no later than December 31, 2022. New full avoided cost rates stemming from each competitive solicitation will be filed with the Commission for review and approval within 30 days of the conclusion of each competitive solicitation;

e. The Company will seek term lengths for competitively bid projects up to 25 years, at the discretion of the bidder;

f. The Company will seek to acquire the target amount of capacity identified in the PCA for each Annual Solicitation period and may exceed that target amount depending on the amount of bids, the size of projects bid, cost and value, and variations in project commercial operation dates. Total newly acquired capacity will be reconciled against the amount of capacity projected in the PCA in the Company's next IRP. (For example, if the Company acquired more capacity than planned, the proposed resource plan in the next IRP would incorporate that additional capacity with a potential reduction in the capacity needed going forward.);

g. If the Company is unable to meet the target capacity amount identified in the PCA in any given Annual Solicitation, the remaining "open" capacity will not be offered to QFs. The remaining capacity would instead be addressed through the process described in Paragraph 8.f.;

h. The parties agree and acknowledge that there are supply chain, energy security, labor, and environmental benefits associated with robust, local clean energy manufacturing capabilities. As part of the Company's competitive bidding process, the parties agree that the Company will, to the extent

reasonably possible, incorporate clear, fair, and transparent criteria in the bid evaluation process to recognize value associated with clean energy supply chain diversification and sustainability, including intended use of Michigan manufactured components and low-carbon manufacturing as verifiable by life cycle assessment and/or disclosure using public, third-party verified environmental product declarations. The Company agrees to consult with parties to the settlement on the details of such bid evaluation criteria. Nothing in this settlement alters the opportunity for stakeholders and potential bidders to review and comment on any new proposed bidding criteria through the process as set forth in the MPSC's competitive bidding guidelines approved in MPSC Case No. U-20852 on September 9, 2021;

i. The parties agree that the Annual Solicitation process does not restrict the Company's ability to make short-term capacity additions to address capacity shortfalls which cannot reasonably be addressed through the Annual Solicitation process; and

j. The Company may pursue supply-side resource pilots for new and emerging technologies outside of an Annual Solicitation subject to cost and project approval in its future rate cases.

9. The parties agree that the new capacity that the Company intends to procure through the PCA, in each Annual Solicitation, shall be: (i) acquired through a competitive bidding process; and (ii) approximately 50% will be from PPAs and other third-party agreements that do not result in Company ownership and approximately 50% will be owned by the Company, as acquired through a competitive bidding process. The new capacity acquired from PPAs or other third-party agreements that do not result in Company ownership will not compete against the new capacity which will be owned by the Company. The Company will use commercially reasonable efforts to maintain the 50%/50% proportion for new IRP resources from 2022 through the Company's next IRP proceeding, and in no event shall any given annual solicitation result in the Company owning more than 60% of the new capacity acquired in such solicitation. The Company, in its sole discretion, may also choose to acquire more than 50% of its new capacity from third parties. The parties further agree that the Company's affiliates will

be prohibited from bidding on the portion of the Company's new capacity acquired from third parties.

10. The parties agree to the approval of the extension of the Company's FCM approved in Case No. U-20165 equal to the product of: (i) the annual PPA payment, and (ii) the Company's after-tax WACC based on its total capital structure, which is currently 5.62%, as updated from time to time by the MPSC in electric rate case final orders. The FCM will be applicable to all new PPAs, but will not apply to PPA amendments, PURPA PPAs, and Voluntary Green Pricing PPAs. The Company shall also not receive an FCM on any PPAs executed under the Company's Renewable Energy Plan. The FCM will be subject to the cap, as provided in Attachment A of the Settlement Agreement. The parties agree that nothing in this Settlement Agreement is intended to waive the requirements of MCL 460.6t(15).

11. The parties agree to the extension of the Company's PURPA avoided cost construct, as approved in Case No. U-20165 (based on the Company's Annual Solicitations), with certain modifications included below:

a. The Company's PURPA avoided cost construct will be subject to review in the Company's future IRP filings, as opposed to separate biennial filings;

b. QFs 150 kWac and below are eligible to receive full avoided cost rates regardless of the Company's capacity needs;

c. Within 180 days subsequent to the Commission's approval of this Settlement Agreement, the Company shall initiate stakeholder outreach to develop a simplified agreement, tariff-based program, or other mechanism which will allow QFs 150 kWac and below to receive full avoided cost rates. Subsequent to the completion of the stakeholder outreach, at the earliest practicable date, the Company will file a proposal with the Commission for approval;

d. When the Company does not have a PURPA capacity need, QFs above 150 kWac, that the Company has a legal obligation to purchase from under PURPA, are eligible to receive the Company's energy-only avoided cost rates. The Company's energy-only avoided cost rates shall be based on a forecast of LMPs for the first 5 years and actual LMPs for years 6 through 10. The

Company's energy-only avoided cost rates shall not include a payment for capacity;

e. Current existing QFs, at or below the Company's PURPA must-purchase obligation MW threshold, with a PURPA-based PPA with the Company as of January 1, 2019 shall receive new PPAs, regardless of the Company's capacity need, upon the expiration of their current PPAs based on the Company's full avoided cost rates at the time of PPA expiration. QFs that entered a PPA with the Company prior to January 1, 2019 at an amount less than full avoided cost rates, such as reduced avoided cost rates based on the Planning Resource Auction ("PRA") rate and forecasted or actual LMPs and energy-only rates which only include an energy rate and do not provide a payment for capacity, shall not automatically receive a new PPA at the full avoided cost rate when their current PPA expires. QFs that have entered a PPA with the Company after January 1, 2019 are not eligible to receive a new full avoided cost rate PPA with the Company regardless of the Company's capacity need;

f. QFs that the Company has a legal obligation to purchase from under PURPA, and which are eligible for full avoided cost rates, may select PPA terms up to 20 years; and

g. QFs up to 5 MWac, that the Company has a legal obligation to purchase from under PURPA, are eligible for the Company's PURPA Standard Offer Tariff and Standard Offer Contract. The terms of the Standard Offer Contract will also be updated from using the MISO methodology for capacity accreditation at the time of PPA execution, to the average of the MISO methodologies at the time of PPA execution and delivery under the PPA. Within 30 days following the Commission's approval of this Settlement Agreement, the Company shall file revised Standard Offer tariff sheets and a revised Standard Offer contract, to reflect the Standard Offer construct and rates approved as part of this Settlement Agreement. Parties shall be given 14 calendar days subsequent to the Company's filing to provide comments to the Commission.

12. The Company has no PURPA capacity need so long as the Company is implementing the Commission-approved PCA, as provided in Paragraph 1, including the competitive Annual Solicitation process for future capacity needs.

13. The parties agree that the Company will donate $5 million in 2022 to a low-income fund that provides bill assistance to Consumers Energy's electric customers. The Company will also donate $2 million annually to the same low-income fund each year during the amortization period for the regulatory asset, provided in Paragraph 5 of this Settlement

Agreement, with each annual donation contingent on the Company filing and the Commission approving a Voluntary Revenue Refund ("VRR"). The donations described in this paragraph will not be recovered in rates and Consumers Energy will consult with the Attorney General and Staff on the low-income fund receiving the donations. The Company will provide an annual report to the Commission each year a donation is made. If known, the report will include the number of households served, the number of households over 150% of the federal poverty level ("FPL"), and number under 150% of the FPL. For those households 150% of FPL and under, the report will explain, if known, whether they are receiving the funds because they exhausted other benefits such as the Michigan Energy Assistance Program or State Emergency Relief.

14. In future IRPs, beginning with its next IRP, the Company will (i) collect the necessary data to compute marginal line losses and report these with average line losses and (ii) include marginal line losses and avoided transmission and distribution costs in its evaluation of all distributed resources, including residential DR potential.

15. Consumers Energy agrees to develop a distributed generation as a resource model approach that considers economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers. The Company agrees to present the model approach for stakeholder review and feedback prior to the next IRP. The model approach, including any incorporated stakeholder feedback, will be included into the Company's next IRP.

16. The parties agree that Consumers Energy's IRP set forth a proposal to be Carbon Neutral by 2040 and retire all coal generation by 2025, 14 years ahead of the original timeline. These retirements include two substantial coal and gas units totaling approximately 2,000 MW. To replace the capacity, Consumers Energy has proposed adding existing natural gas-fired generation and plans to add about 8,000 MW of solar generation by 2040, to dramatically reduce the use of fossil fuel resources. The next IRP should consider transmission and how it can facilitate the mitigation of reliability and economic impacts to the electric system. The parties also agree that strategic investment in electric transmission needs continual assessment to understand the role of transmission in allowing for the most economic path to meeting the state's energy goals while complementing Michigan's Load Serving Entities' ("LSE") objectives. Michigan is transitioning its generation portfolio and must take the appropriate steps to increase system reliability, resiliency, flexibility, and affordability. Michigan will be better positioned by taking a forward-looking approach regarding resource adequacy. The state should continue to recognize and support the value of a multitude of resources such as Solar, Wind, DR, and Distributed Energy Resources which assist in an "all of the above" approach. Transmission is essential in delivering the reliability of these resources. The value of transmission can be even further realized by leveraging those transmission resources to better assist the Consumers Energy IRP. This will allow MISO LRZ 7 to access broader pools of generation resources, be better situated for future demands placed on the system, mitigate unnecessary risks, and increase performance of those "all of the above" resources to serve the demands of Michigan's customers reliably and economically.

17. The parties agree that the Company will include the following analysis in its next IRP:

a. The Company will provide total emissions, in lbs or tons, and rate of emissions, in lbs or tons per MWh and per MMBtu, for each owned power plant unit, or units that that the Company has a power purchase agreement with, for the last 5 years of operation (for existing units) and projected for the next 5 years (for all units) for the following pollutants: carbon dioxide, nitrogen oxides, sulfur dioxide, volatile organic compounds ("VOCs"), and primary particulate matter ("PM2.5");

b. The Company will calculate the annual PM2.5-related health impacts associated with each power plant's emissions. The modeling will include the impacts from primary PM2.5 emissions and PM2.5 precursors emissions (nitrogen oxides, sulfur dioxide, VOCs). The Company will use one model to evaluate the number and economic value of PM2.5-related health impacts of these emissions. The Company may use COBRA or BenMAP (which will require pollutant change inputs from another model such as InMAP) for these calculations, or models that are of equal or greater complexity and accuracy. The Company will report the total number and economic value of PM2.5-related health impacts across the US for the chosen model and spatially by Michigan county or at a higher resolution;

c. The Company will use the MiEJScreen mapping and screening tool, or, if the MiEJScreen tool is not yet finalized, the EPA Environmental Justice Screening and Mapping Tool ("EJSCREEN"), to assess populations in a 1-mile and 3-mile buffer around each power plant location, including reporting total populations and any indicators and total index results above the 75th percentile;

d. The Company will report projected low-income energy efficiency participation levels, low-income load-reduction data, and publicly available rooftop solar adoption rates. If available, information on rooftop solar adoption by low-income customers will be provided;

e. The Company will include a narrative discussion of how the data obtained in a-d were considered by the utility; and

f. To the extent that the Commission formally adopts revised Integrated Resource Plan Filing Requirements and/or revised Michigan Integrated Resource Planning Parameters that address environmental emissions, health impacts from emissions, or environmental justice, such filing requirements will supersede the terms of this Paragraph 17.

18. The parties agree that the Company will take the following steps to engage and gather input from the public prior to the filing of its next IRP with the Commission:

a. Host meetings about the topic of the filing at a variety of times, during the daytime and the evening, with the Company providing equivalent content and equivalent and sufficient time for robust public response at each session;

b. Host meetings about the topics in the filing with a roughly equal mix between (i) in-person meetings and (ii) virtual or hybrid meetings;

c. For the duration of the proceedings before the MPSC, make available on its website recordings of (i) all virtual or hybrid meetings and (ii) to the extent feasible, any portion of an in-person meeting in which the Company is (a) addressing all participants in the meeting and/or (b) receiving public feedback and/or questions in a format intended to be heard by all participants in the meeting at the same time;

d. When requested 10 business days prior to a meeting, provide translations of materials for the benefit of those communities whose first language is not English, based on the demographics of the community;

e. When requested within 30 days subsequent to a meeting, the Company will use best efforts to provide a translation of recordings of the community meeting in a language specified by the person requesting the translation. Such translation recordings will be provided within 15 business days, subject to the Company's best efforts, after the request is received. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the recording into the language requested, the Company will not be obligated to provide the translation;

f. When requested at least 10 business days prior to an in-person meeting, the Company will use best efforts to include at least one live interpreter who can translate in the requested language. If the Company is unable, after a good faith effort, to find or reasonably engage the services of a translator capable of translating the meeting into the language requested, the Company will not be obligated to provide the translation;

g. Coordinate with community-based organizations when organizing and promoting meetings about the filing. The Company will solicit input regarding the time, place, and manner of the meetings from the community organizations, in addition to any other meetings the Company wishes to hold of its own accord;

h. Use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health;

i. Include in its filings a concise general statement of the basis and purpose of the comments received by the Company and how the Company considered,

addressed, or rejected the issues raised in those comments in the IRP (as practicable); and

j. Subsequent to the issuance of the Commission's order approving this Settlement Agreement, the Company agrees to meet with UCC to discuss potential stakeholder outreach prior to or subsequent to future electric rate case filings.

19. The parties agree that the Company will do the following with respect to combined heat and power ("CHP") resources:

a. Within 180 days of the effective date of the Commission's order approving the settlement, the Company will initiate a voluntary survey among its commercial and industrial customers to gauge interest in CHP (the "CHP survey"), with survey responses intended to be used by the Company to support the evaluation of: (1) the types of CHP that customers prefer, with regard to size, technology and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company, and: (2) non-confidential information regarding locations within the Consumers Energy territory that may be most appropriate for deployment of CHP. The CHP survey will be conditioned on respondent approval of the public release of all information provided by the respondent in response to the survey. Nothing in this section is intended to require the public release of any confidential and/or commercially sensitive customer or Company information;

b. Within 360 days of the effective date of the Commission's order approving the settlement, the Company will share the results of the CHP survey in the Case No. U-21090 e-docket, including a summary of the types of CHP that customers prefer, with regard to size, technology, and overall configuration, on both the demand side and supply side, including co-ownership arrangements and other potential partnerships with the Company; and a summary of non-confidential information regarding locations within the Company's territory that may be most appropriate for deployment of CHP, according to the CHP survey results;

c. In its next IRP proceeding, the Company will model behind-the-meter CHP representative of a demand-side resource based upon the results from the CHP survey as appropriate; and

d. In its next IRP proceeding, the Company will model front-of-the-meter CHP configurations based upon the results from the CHP survey as appropriate.

20. This settlement is entered into for the sole and express purpose of reaching a compromise among the parties. All offers of settlement and discussions relating to this settlement are, and shall be considered, privileged under MRE 408. If the Commission approves this Settlement Agreement without modification, neither the parties to this Settlement Agreement nor the Commission shall make any reference to, or use, this Settlement Agreement or the order approving it, as a reason, authority, rationale, or example for taking any action or position or making any subsequent decision in any other case or proceeding; provided, however, such references may be made to enforce or implement the provisions of this Settlement Agreement and the order approving it.

21. This Settlement Agreement is based on the facts and circumstances of this case and is intended for the final disposition of Case No. U-21090. So long as the Commission approves this Settlement Agreement without any modification, the parties agree not to appeal, challenge, or otherwise contest the Commission order approving this Settlement Agreement. Except as otherwise set forth herein, the parties agree and understand that this Settlement Agreement does not limit any party's right to take new and/or different positions on similar issues in other administrative proceedings, or appeals related thereto.

22. This Settlement Agreement is not severable. Each provision of the Settlement Agreement is dependent upon all other provisions of this Settlement Agreement. Failure to comply with any provision of this Settlement Agreement constitutes failure to comply with the entire Settlement Agreement. If the Commission rejects or modifies this Settlement Agreement or any provision of the Settlement Agreement, this Settlement Agreement shall be deemed to be withdrawn, shall not constitute any part of the record in this proceeding or be used for any other purpose, and shall be without prejudice to the pre-negotiation positions of the parties.

23. The parties agree that approval of this Settlement Agreement by the Commission would be reasonable and in the public interest.

24. The parties agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281), as it applies to the issues resolved in this Settlement Agreement, if the Commission approves this Settlement Agreement without modification.

WHEREFORE, the undersigned parties respectfully request the Commission to approve this Settlement Agreement on an expeditious basis and to make it effective in accordance with its terms by final order.

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

By: Spencer Sattler Digitally signed by Spencer Sattler Date: 2022.04.19 14:00:30 -04'00' Date: April 19, 2022

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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'

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By: Richard Aaron

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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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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

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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

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ATTACHMENT A

ATTACHMENT A

Contract Year	Total Rate ($/MWh)
2019	**$ 55.54**
2020	**$ 57.49**
2021	**$ 59.38**
2022	**$ 61.28**
2023	**$ 63.25**
2024	**$ 65.24**
2025	**$ 67.24**
2026	**$ 69.24**
2027	**$ 71.23**
2028	**$ 73.18**
2029	**$ 75.08**
2030	**$ 76.95**

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-21090

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on June 23, 2022 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 23rd day of June 2022.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2024

Service List for Case: U-21090

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Attachment GG

DOE, Air Quality and Environmental Justice Memorandum (2021)

Department of Energy
Washington, DC 20585

October 1, 2021

Enclosed is the final special environmental analysis (DOE/SEA-05) prepared by ICF, Incorporated (ICF) under direction of the Department of Energy (DOE) pursuant to the National Environmental Policy Act of 1969 (NEPA), 42 U.S.C. 4331 et seq., and DOE's implementing regulations, 10 CFR 1021.343(a).

On February 14, 2021, DOE issued an emergency order pursuant to section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the DOE Organization Act, 42 U.S.C. § 7151(b), DOE Order No. 2020-21-1, to the Electric Reliability Council of Texas (ERCOT) authorizing specific electric generating units located within the ERCOT area to operate at their maximum generation output levels under limited circumstances due to extreme weather conditions and to preserve the reliability of bulk electric power system (Order).

DOE issued the Order after determining that the emergency situation underlying ERCOT's request demanded immediate action consistent with DOE's NEPA regulations (10 CFR 1021.343(a)). As described in DOE's notice of emergency action (86 FR 18046; April 7, 2021), DOE reviewed the final data report received from ERCOT on March 31, 2021, and determined that a special environmental analysis would be the appropriate level of NEPA review. DOE has prepared special environmental analyses in other emergency situations that required immediate action. (See https://www.energy.gov/nepa/special-environmental-analyses). This special environmental analysis examines potential impacts resulting from issuance of the Order on air quality and environmental justice. DOE has independently reviewed the analysis provided by ICF and agrees with its conclusions. No further analysis will be conducted.

U.S. Department of Energy, Office of Electricity

Air Quality and Environmental Justice Analysis Memorandum, July 21, 2021

Introduction

During 5 days in February 2021 (February 15–19), the Electric Reliability Council of Texas (ERCOT) requested the Department of Energy (DOE) to authorize the emergency use of power generation under Section 202(c) of the Federal Power Act. This resulted in air emissions at times exceeding their permitted emissions levels for 28 power units located in East Texas, with most power units (20) located in Harris County. At the request of the DOE Office of Electricity (OE), ICF has examined whether these additional emissions from these power units covered by the Section 202(c) authorization may have led to an exceedance of the National Ambient Air Quality Standards (NAAQS). Further, ICF conducted an environmental justice analysis of the communities potentially affected by any additional emissions during this 5-day period.

We determined at the outset that for one power unit, ERCOT was unable to obtain any information on its air emissions. Therefore, our analyses included 27 units. Although the ERCOT Section 202(c) permit covered 27 power units, only 14 of the 27 power units were at unique locations.

1 Air Quality Analysis Approach

To assess whether emissions from the power units could potentially contribute to a NAAQS violation, ICF gathered the air quality monitoring data for stations in East Texas. The Texas Commission on Environmental Quality (TCEQ) maintains an extensive network of air monitoring stations throughout the state.[1] This hourly air monitoring and meteorological data, resultant wind speed and direction, outdoor temperature, standard deviation in wind direction, and solar radiation were downloaded from TCEQ. In addition, ERCOT provided the locations for each power generating unit. Using this collected data, ICF determined if any exceedances occurred during the emergency period (February 15–19, 2021) for air pollutants having short-term ambient air quality standards. This included 1- and 8-hour CO, 1-hour NO_2, 1-hour SO_2, and 24-hour PM^2 standards. No assessment was made for mercury or CO_2 emissions.

ERCOT provided DOE with hourly air emission rates for each unit above its permitted levels, along with the location of each power unit. This information was used to pair air quality monitoring stations with power units. We examined pairings using proximate radial distances of 10 km and 15 km. To determine if an air monitoring station was downwind of the power unit, we used each hour's wind direction to determine if the air monitoring station aligned in a downwind direction within a ±20-degree window.

To further strengthen conclusions, we compared the 5-day average temperature with historical average February temperatures using climatological data from Houston International Airport as an overall representative site. Lower than average temperatures are favorable for increased

[1] https://www.tceq.texas.gov/cgi-bin/compliance/monops/select_month.pl

[2] Although PM_{10} is the reported emission rate, we used the $PM_{2.5}$ standard, as nearly all (>97 percent by mass) of the power plant emissions have a mean mass diameter of less than 2.5 microns.

buoyancy from the exhaust stack, which means the plume will rise higher, favoring lower ground-level air concentrations. A similar analysis was performed for wind speeds but using the Houston Aldine site (EPA AIRS ID 48_201_0024). Here, higher wind speeds led to increased ventilation, which decreases residence time of air pollutants, leading to lower air pollutant concentrations.

Lastly, we discuss the concept of mixing height. The *mixing height* (or depth) is defined as the height above the Earth's surface through which vertical mixing occurs. The concept of a mixing layer is well-founded on theoretical principles. The mixing height acts as a lid on air pollutants, tending to prevent further vertical mixing of emissions higher into the atmosphere. Thus, we calculated the mixing heights during the 5-day emergency period and compared them to the average February mixing heights based on the Holzworth method (U.S. Environmental Protection Agency, 1972). Mixing heights can be determined from twice daily upper-air soundings performed at 6 a.m. and 6 p.m. The nearest upper-air station to Harris County is Lake Charles, Louisiana.

Review of ERCOT Emission Rates Against Total Emissions Rates During the Emergency Use Period

We reviewed the hourly emission rate data provided by ERCOT for each power unit. The dataset is intended to report the incremental emissions for each hour that exceeded the power units' maximum permitted emission rates. To compare these incremental emissions against the total emissions from each power unit, we downloaded the Continuous Emission Monitoring System (CEMS) from EPA's Air Markets Program Data (ampd.epa.gov/ampd). CEMS data reports the total emissions for each power unit on an hour-by-hour basis either as directly measured or as calculated from other measured parameters. The ERCOT data reported hourly emissions for SO_2, NO_X, CO, PM_{10}, and CO_2; however, CEMS does not report emissions for CO and PM_{10}, so the only pollutants that can be cross-referenced between the two datasets are SO_2, NO_X, and CO_2. However, SO_2 and CO_2 are rarely reported in the ERCOT-supplied data, likely because SO_2 emission rates are well below permitted levels even during the emergency period, and CO_2 emission rates are likely not specified in operating permit levels.

Because the ERCOT emission rates are in, we expected that in most cases the ERCOT incremental increase would only be a small fraction of the total CEMS rates and that the ERCOT rates could never be greater than CEMS rates because CEMS emissions are the total emissions from the power units. To see if our understanding is consistent with the reported data, we made a graphical presentation between the NO_X incremental emission rate versus the CEMS emissions rate for each hour in which ERCOT reported an emission rate over the 5-day emergency period.

1.1 Findings – Potential for NAAQS Exceedances

We discuss a series of analyses undertaken using available air quality and meteorological data to present a weight-of-evidence approach in trying to answer the principal question—*Could the power units' excess air emissions during this emergency period have caused an exceedance of the NAAQS?*

No one analysis can definitively answer this question, so we performed a series of analyses to provide a more defensible and robust conclusion and instill greater confidence in the answer.

1.1.1 Air Quality Monitoring Stations

A review of air quality monitoring stations in all air quality modeling regions in East Texas showed no violations of the NAAQS during the emergency period. However, many of the air quality monitoring stations failed to operate during the emergency period, presumably because of power outages. Tables 1a and 1b below show the daily percentage of missing air quality data during the emergency period for power units and air quality stations that we could pair using a 10-m radius. Only 14 of the 27 power units had unique locations, and of the 14 locations, only 10 had an air quality station within 10 km. The pollutant most widely monitored, as well as the pollutant most widely reported as having emissions exceeding permit levels, is NO_X. Of the 14 locations, seven had NO_2 monitors.[3] However, as highlighted in light blue and indicated with an asterisk (*), about half have missing data (likely as a result of power outages), particularly on the first 3 days of the emergency period. Other air pollutants have less air monitoring coverage but also show considerable missing data, particularly during the first 3 days of the emergency period.

The power unit codes shown in the rest of this report are defined in Appendix 1.

[3] Although the emitted pollutant is NO_X, the air quality standard is for NO_2. Typically, about 10 percent of the in-stack NO_X is in the form of NO_2, and the rest is emitted as NO. However, NO is converted to NO_2 in the atmosphere with a reaction rate on the order of minutes to hours, depending on available ozone and atmospheric mixing.

Table 1a. Ambient Air Quality Monitoring Stations (CO and NO_2) Within 10 km of the Power Generation Units

Power Unit Name	Pollutants of Interest Monitored				Data Coverage by Day CO					Data Coverage by Day NO_2				
	CO	NO_2	$PM_{2.5}$	SO_2	2/15	2/16	2/17	2/18	2/19	2/15	2/16	2/17	2/18	2/19
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FREC_CC2				X										
TXCTY_CC1				X										
CHAMON_CTG_0101		X								75%	0%*	17%*	100%	100%
CALHOUN_UNIT1														
THW_THWGT32		X								100%	92%	38%*	100%	100%
WAP4_WAP4														
GBY_GBYGT74		X	X							100%	96%	50%	100%	100%
PHR_CLCWA_5UNITS		X								8%*	88%	42%*	100%	96%
LH_LYN_30UNITS		X								75%	0%*	17%*	100%	100%
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	21%*	0%*	50%	100%	100%	21%*	75%	100%	100%
FEGC_UNIT1				X										

See Appendix 1 for definition of the unit codes.

Table 1b. Ambient Air Quality Monitoring Stations (PM25, SO_2) Within 10 km of the Power Generation Units

	Pollutants of Interest Monitored				Data Coverage by Day $PM_{2.5}$					Data Coverage by Day SO_2				
Power Unit Name	**CO**	**NO_2**	**$PM_{2.5}$**	**SO_2**	**2/15**	**2/16**	**2/17**	**2/18**	**2/19**	**2/15**	**2/16**	**2/17**	**2/18**	**2/19**
BOSQUE_CC1														
DDPEC_CC1	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FREC_CC2				X						0%*	0%*	0%*	46%*	100%
TXCTY_CC1				X						100%	100%	100%	100%	100%
CHAMON_CTG_0101		X												
CALHOUN_UNIT1														
THW_THWGT32		X												
WAP4_WAP4														
GBY_GBYGT74		X	X		100%	92%	33%*	0%*	50%					
PHR_CLCWA_5UNITS		X												
LH_LYN_30UNITS		X												
DSN_NEWP_10UNITS														
SOE_SEWP_10UNITS	X	X	X	X	100%	17%*	71%	100%	83%	100%	21%*	67%	100%	100%
FEGC_UNIT1				X						0%	0%	0%	0%	25%

Increasing the search radius from 10 km to 15 km picked up two additional air quality monitoring stations; however, the influence from the power station at that distance is substantially diminished, particularly in urban environments, where other sources of emissions will affect the monitor.

Tables 2a and 2b show the three highest monitored concentrations for NO_2, $PM_{2.5}$, and SO_2 over the 5-day period.[4] The only pollutant within 50 percent of the air quality standard was $PM_{2.5}$, although the $PM_{2.5}$ standard is an average over 24 hours, whereas those for NO_2 and SO_2 are 1-hour standards. No exceedances of any air quality standard occurred at these stations, nor at any air quality monitoring stations in the region of study. The highest concentration, to any air quality standard, was for the 24-hour $PM_{2.5}$ standard at 56 percent.

The highest elevated $PM_{2.5}$ concentrations all occurred during the late evening hours (8 p.m.–11 p.m.) on February 19, 2021. Many sources contribute to $PM_{2.5}$ pollution, including buses, trucks, cars, and off-road sources (e.g., construction equipment, portable generators). In addition, meteorology and atmospheric chemistry play a significant role in determining the air concentration. However, it is not possible from this analysis to estimate the source contribution from the power units without additional air quality modeling analysis.

Table 2a. Top 3 Highest Air Concentrations Monitored Within 10 km of the Power Generation Units

Power Unit	NO_2 (ppb)			$PM_{2.5}$ (µg/m^3)			SO_2 (ppb)		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
DDPEC_CC1	37	33	29	17	12	11	1	1	1
FREC_CC2							0	0	0
TXCTY_CC1							3	2	2
CHAMON_CTG_0101	31	30	29						
THW_THWGT32	37	37	36						
GBY_GBYGT74	40	36	35	20	14	14			
PHR_CLCWA_5UNITS	27	18	17						
LH_LYN_30UNITS	31	30	29						
SOE_SEWP_10UNITS	37	33	29	17	12	11	1	1	1
FEGC_UNIT1							0	0	0

Note: For NO_2 and SO_2 these are 1-hour averages; $PM_{2.5}$ is a daily average.

Table 2b. Top 3 Highest Air Concentrations (as Percentage of Air Quality Standard[a]) Monitored Within 10 km of the Power Generation Units

Power Unit	NO_2			$PM_{2.5}$			SO_2		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
	37%	33%	29%	48%	34%	30%	1%	1%	1%
FREC_CC2							0%	0%	0%
TXCTY_CC1							3%	3%	3%
CHAMON_CTG_0101	31%	30%	29%						
THW_THWGT32	37%	37%	36%						
GBY_GBYGT74	40%	36%	35%	56%	40%	39%			
PHR_CLCWA_5UNITS	27%	18%	17%						

[4] CO is not shown because the values were <1 percent of the NAAQS.

Power Unit	NO_2			$PM_{2.5}$			SO_2		
Unit Code	**First**	**Second**	**Third**	**First**	**Second**	**Third**	**First**	**Second**	**Third**
LH_LYN_30UNITS	31%	30%	29%						
SOE_SEWP_10UNITS	37%	33%	29%	48%	34%	30%	1%	1%	1%
FEGC_UNIT1							0%	0%	0%

[a] The 1-hour NO_2 standard is 100 ppb, 1-hour SO_2 standard is 75 ppb, and 24-hour $PM_{2.5}$ standard is 35 µg/m3.

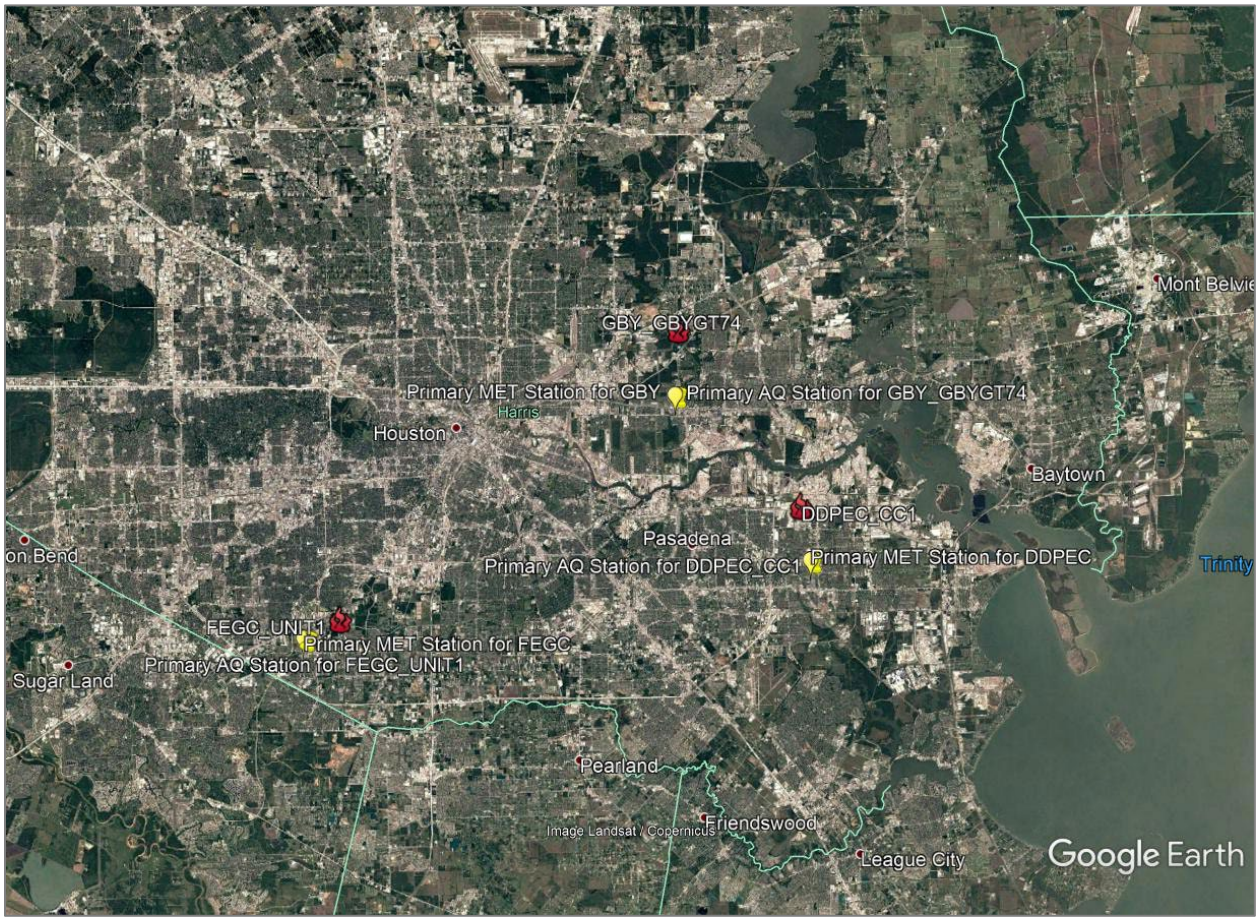
1.1.2 Downwind Air Quality Monitoring Sites

Besides being in close proximity to the power unit, an air quality monitoring station must also be oriented in the downwind direction of the power unit. Table 3 shows the percentage of time that the air quality monitoring station was downwind of the power unit. As shown, only one air quality monitoring site was downwind more than 50 percent of the hours. All other pairs of air quality monitoring stations and power units only had the correct alignment window 25 percent or less of the time. The air quality monitoring unit paired with the Deer Park Energy Center (DDPEC_CC1) power unit was downwind more than half the hours. This was the best pairing of any power unit and air quality station and shows good supporting evidence that the power units' excess emissions were unlikely to have caused an exceedance of the NAAQS (except on February 16, 2021, when the monitoring stations only had valid measurements for 20 percent of the hours that day). All other meteorological/air quality station pairs had too few hours to draw a conclusion. Figure 1 shows the locations of three of the power units relative to the air monitoring stations in Harris County.

Table 3. Power Unit Pairings With Nearby Meteorological Stations and Percentage of Time Downwind

Power Unit Code	Distance to MET Station (km)	AQ Station Direction – Lower Bound	AQ Station Direction – Upper Bound	% of MET Station Data Within +/-20 Degree Range of AQ Station Location
DDPEC	4.9	320°	360°	58%
FREC	10.3	320°	360°	25%
TXCTY	1.4	220°	260°	3%
CHAMON	8.6	0°	40°	6%
THW	17.5	220°	260°	<1%
GBY	5.6	345°	25°	25%
PHR	11.1	135°	175°	<1%
LH	1.2	100°	140°	10%
SOE	5.0	185°	225°	1%
FEGC	3.5	25°	65°	3%

Figure 1. Location of Three Power Units Operating in Harris County and the Paired Air Monitoring Station



1.1.3 Meteorological Conditions Conducive to High Concentrations

Wind Speed

As discussed, lower wind speeds result in poorer dispersive conditions that lead to higher air concentration levels. Average wind speeds for February, based on the 23-year average (1998–2020) from the Houston Aldine site (EPA Airs ID# 48-201-0024), is 6.2 mph. During the 5-day emergency-use period, the winds were slightly higher (14 percent) than the average wind speed of 7.0 mph. Thus, the slightly higher wind speeds are favorable to having lower air concentrations.

Temperature

As discussed, lower temperatures will lead to increased buoyancy, resulting in lower air concentrations. The climatological average air temperature for February at the Houston International Airport is 57.7°F. During the 5-day event, the average air temperature was 28.4°F, almost 30°F below average. These substantially colder temperatures are favorable to having lower ground-level air concentrations, assuming the plume rise from the power units is sufficiently high that these concentrations are not trapped in a shallow stable layer (i.e., temperature inversion) near the surface.

Mixing Heights

We determined mixing height by using the same method as the historical data from Lake Charles (the closest upper air station to Harris County). The February morning mean mixing height during the 5-day emergency event was 530 m, and the afternoon mixing height was 607 m. This compares with a climatological morning mixing height of 319 m in February and a climatological afternoon mixing height of 822 m. The higher mixing height observed during the event reduced the tendency for the trapping of air pollutants in a shallow layer near the Earth's surface, so air concentrations should be lower due to higher mixing height. The lower mixing heights observed during the event in the afternoon relative to the climatological average is the reverse of the morning, but the mean depth of the mixed layer is still higher than the morning period, so in general, concentrations are lower in the afternoon than the morning if emissions are the same.

1.1.4 Emission Rates: ERCOT versus CEMS

To better understand the emissions data, we graphically displayed the ratio of the ERCOT emission rates for NO_X to the CEMS NO_X emission rates for every hour using three representative emission profiles observed during our review of the ERCOT dataset. We report results for three representative types of findings. These are:

1. Peaking Plant, where the ERCOT is thought to be a large fraction of the CEMS data
2. Large amount of volatility in the ERCOT dataset
3. Does not make sense (ERCOT emission rate >> CEMS emission rate)

In no case should the ERCOT to CEMS ratio be greater than 1.

The three representative stations are:

1. Port Comfort Peaking Unit 2
2. Chamon Power Unit 1
3. Bosque CCP-GT-1

Figure 2 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for Port Comfort Peaking unit, with most hours reporting a ratio between 60 to 80 percent of the CEMS emission rate and with the unit off during most of February 18, 2021. A few anomalous hours occur where the ERCOT-to-CEMS ratio exceeds 1. Overall, this pattern appears to be a reasonable behavior.

Figure 2. Port Comfort Peaking Unit Hourly ERCOT/CEMS Emission Ratio During Emergency Period

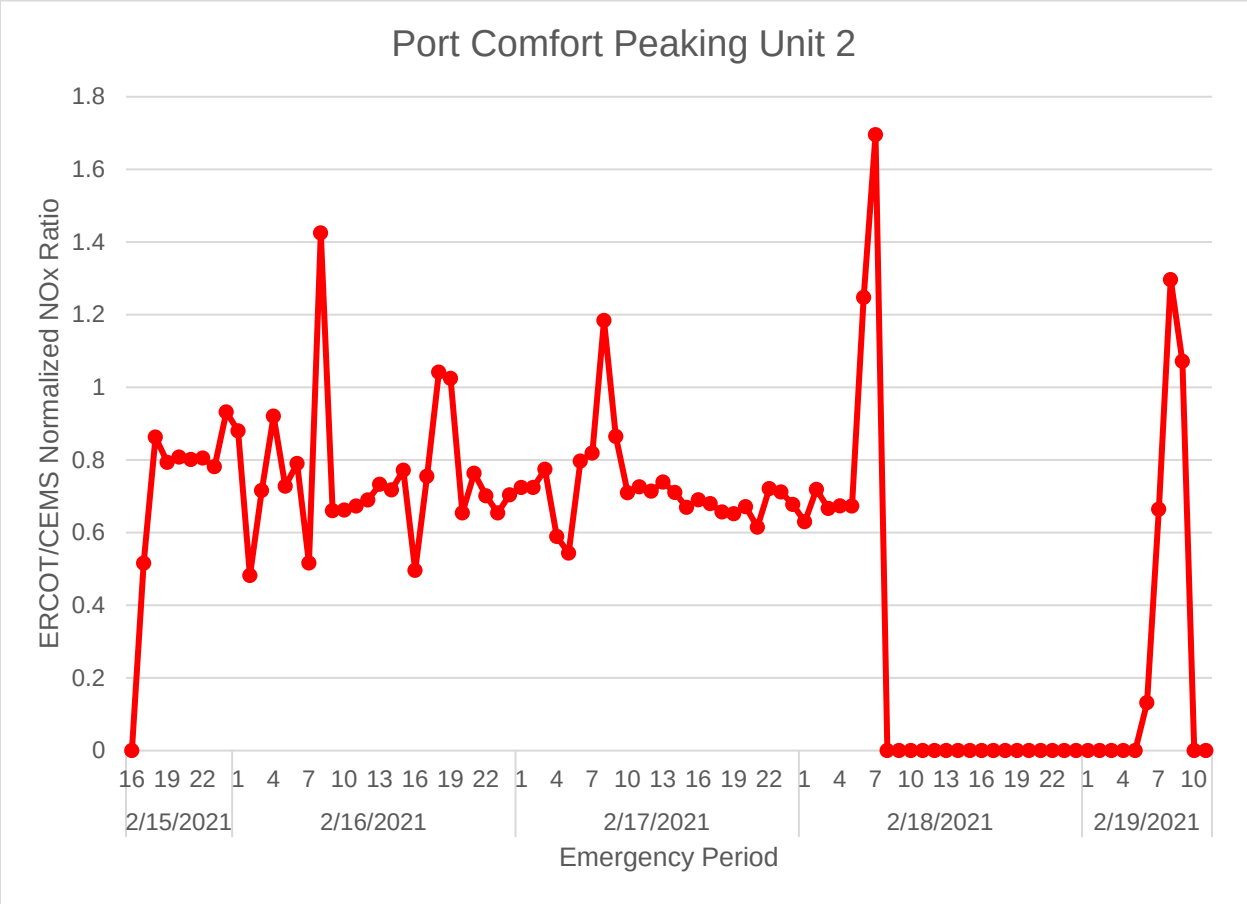


Figure 3 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for the Port Chamon unit, with most hours having a value of less than 100 percent. There are a few hours with a ratio excursion that well exceeds a ratio of 1. Overall, this pattern can likely be explained if further information can be obtained from the plant about the few hourly ratio excursions that were much greater than 1.

Figure 3. Chamon Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period

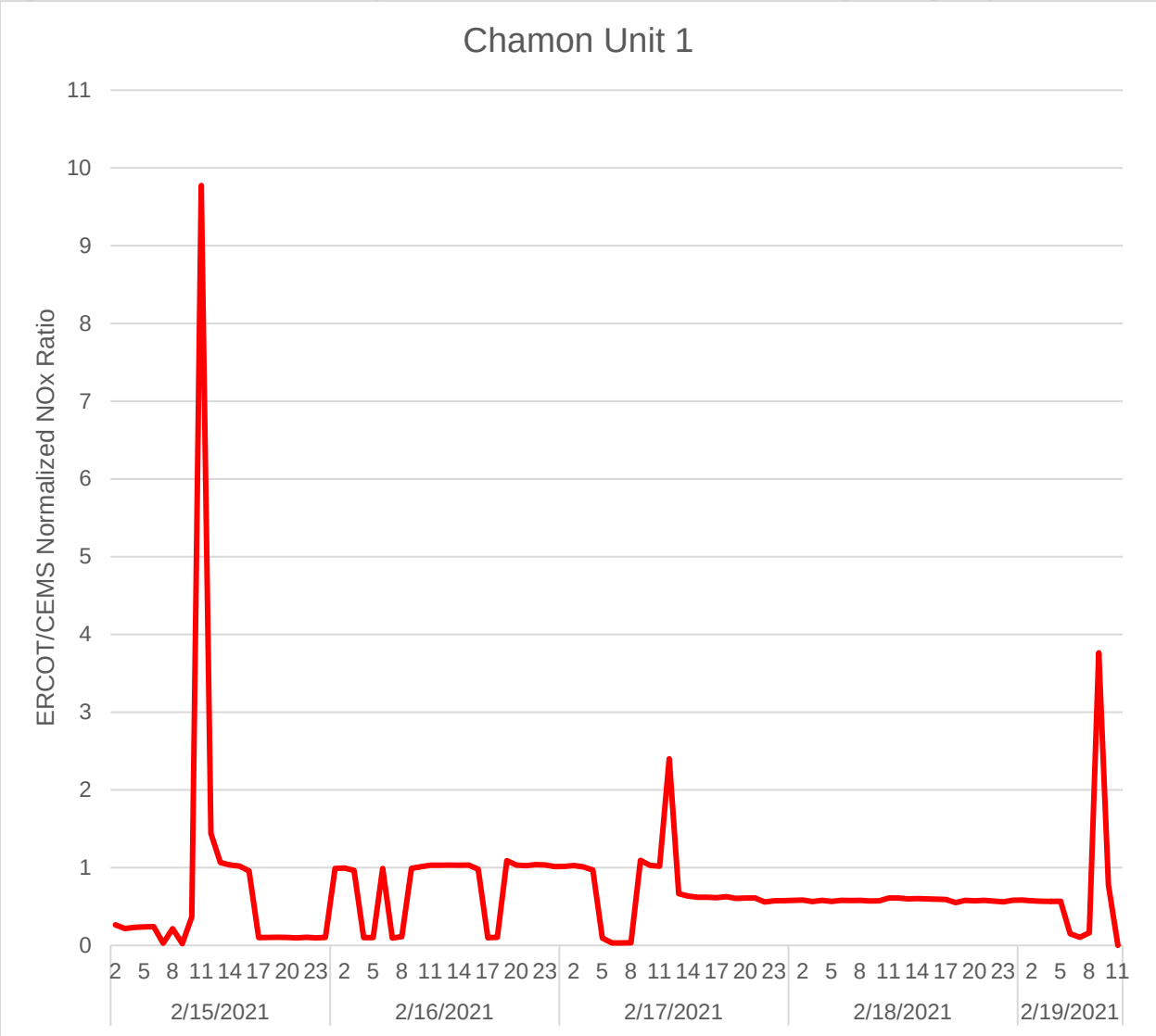
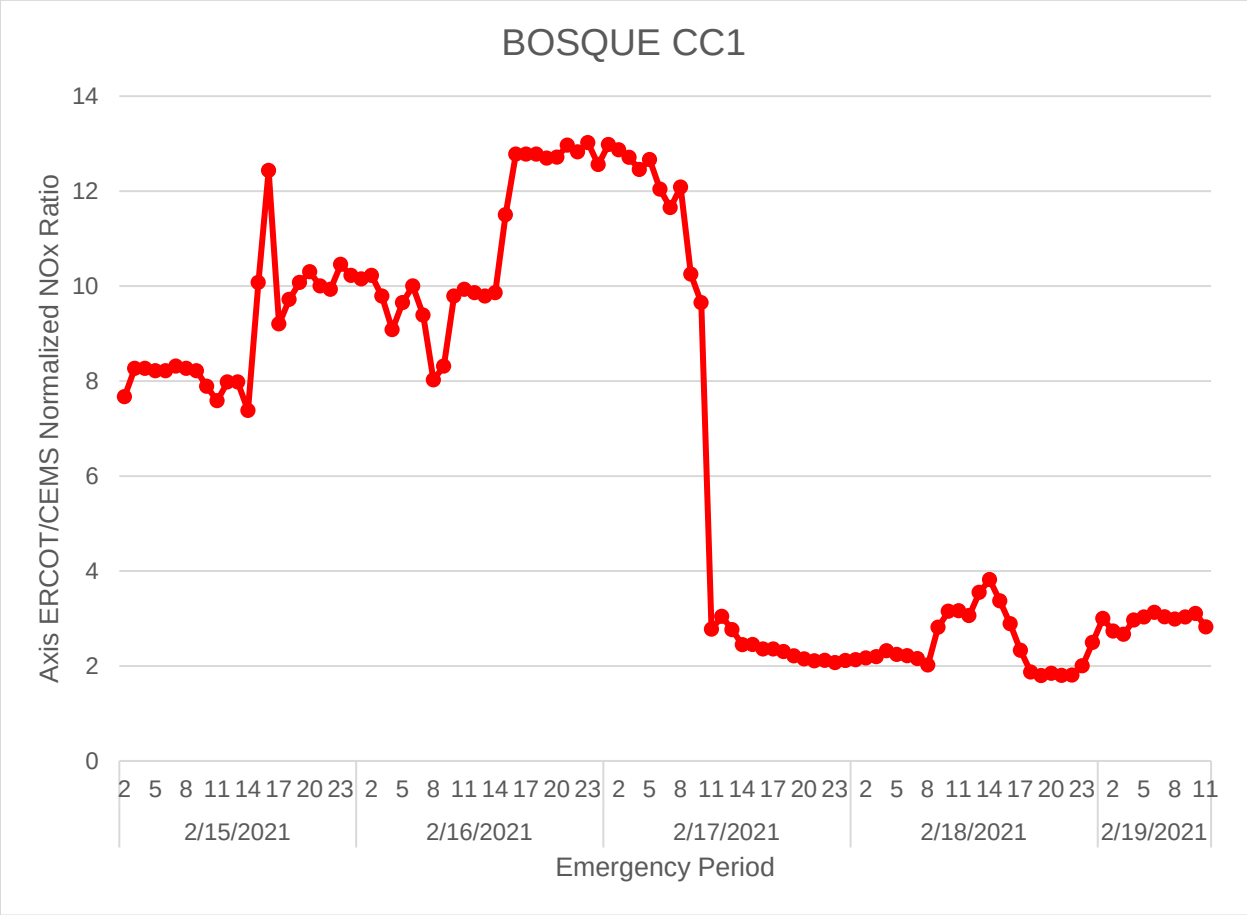


Figure 4 shows the ratio of the ERCOT NO_X emission rate to the CEMS NO_X emission rate for the BOSQUE unit, with all hours having a ratio in excess of 1, or less than 100 percent, but a few hours having a ratio excursion that well exceeds a ratio of 1. In fact, no ratio is less than 2, with a maximum of 13. Overall, these high values in comparison to the CEMS data are irregular. We suspect that incorrect values may have been reported by BOSQUE, as well as other units that exhibited similar behavior. However, further discussion with the plant is needed to clarify this finding.

Figure 4. BOSQUE Unit 1 Hourly ERCOT/CEMS Emission Ratio During Emergency Period



1.2 Conclusions – Air Quality Analysis

We reviewed ambient air quality monitoring data, meteorological data, and emission information for the power units that operated in exceedance of their permitted levels during the emergency use of power generation authorization under Section 202(c). We paired air quality monitoring stations with power units that were near each other. We found parings for 10 of the 14 unique power generation units, most often for NO_2. We found no exceedances of the NAAQS standards; however, many of the air quality stations were missing air quality measurements on February 16 and 17, 2021. The highest concentration, to any air quality standard, was for the 24-hour $PM_{2.5}$ standard at 56 percent of the exceedance threshold value. Further review of the air quality monitoring station and power unit data showed just one air quality monitoring station downwind of the power unit for the majority of hours during the emergency use period. A review and discussion of the meteorological conditions (e.g., wind speeds, temperature, mixing heights)

during the emergency period showed that the meteorology was conducive to better mixing and dispersion than average conditions in February. Reported incremental emissions did not compare favorably with the CEMS data available for NO_X.

Although no exceedances for the NAAQS occurred during the emergency use period, the large percentage of missing data, particularly on February 16 and 17, 2021, make it difficult to conclusively conclude that no violation of the NAAQS may have occurred. Furthermore, the limited number of downwind air quality monitors in close proximity to the power units makes it difficult to definitively conclude there were no air quality exceedances. However, based on the weight-of-evidence approach presented herein, it appears unlikely that the power units may have caused an exceedance of the NAAQS.

2 Environmental Justice Implications for the Affected Population

This section highlights the potential environmental justice (EJ) implications of the affected population in the region of interest. Our evaluation was based on data from U.S. Environmental Protection Agency's (EPA) EJSCREEN tool, available at ejscreen.epa.gov/mapper. EJSCREEN is a tool EPA has developed over the years to allow users to evaluate potential EJ impacts in different parts of the country using a GIS-based mapping platform. The tool allows users to combine demographic and environmental information on a user-selected area. The data used for these purposes in EJSCREEN are based on publicly available data sources, such as the American Community Survey from the Census Bureau for demographic data and various EPA data sources for environmental indicators. We used this screening tool for this analysis because it provides a method consistent with EPA's approach for defining EJ vulnerabilities for affected populations.

2.1 Analyzing Demographic Characteristics of Nearby Population

In order to identify the vulnerable population around these 14 unique power plants and 27 units that are likely to be impacted by any potential exceedances during the 5-day period, we extracted the demographic and environmental characteristics of those living with a pre-specified 5- and 10-km radius around each power plant. Note that we conducted this analysis at the plant level (as opposed to the unit level) because the unique location coordinates were available only at the plant level.

Figure 5 below overlays the 5-km circles around the individual power plants. Most of the plants are located around the Houston area, with a few farther away. Populations living around plants in the Houston area are likely to be more susceptible to potential EJ concerns. There is an overlap between the Lynchburg (LH) and Deer Park Energy Center (DDPEC) plant radii, as well as between the DDPEC and Southeast WPP (SOE) plant radii. Individuals in the intersections may experience EJ effects from both plants, and therefore may be more affected.

Figure 5. 5-km Radius Around Plants

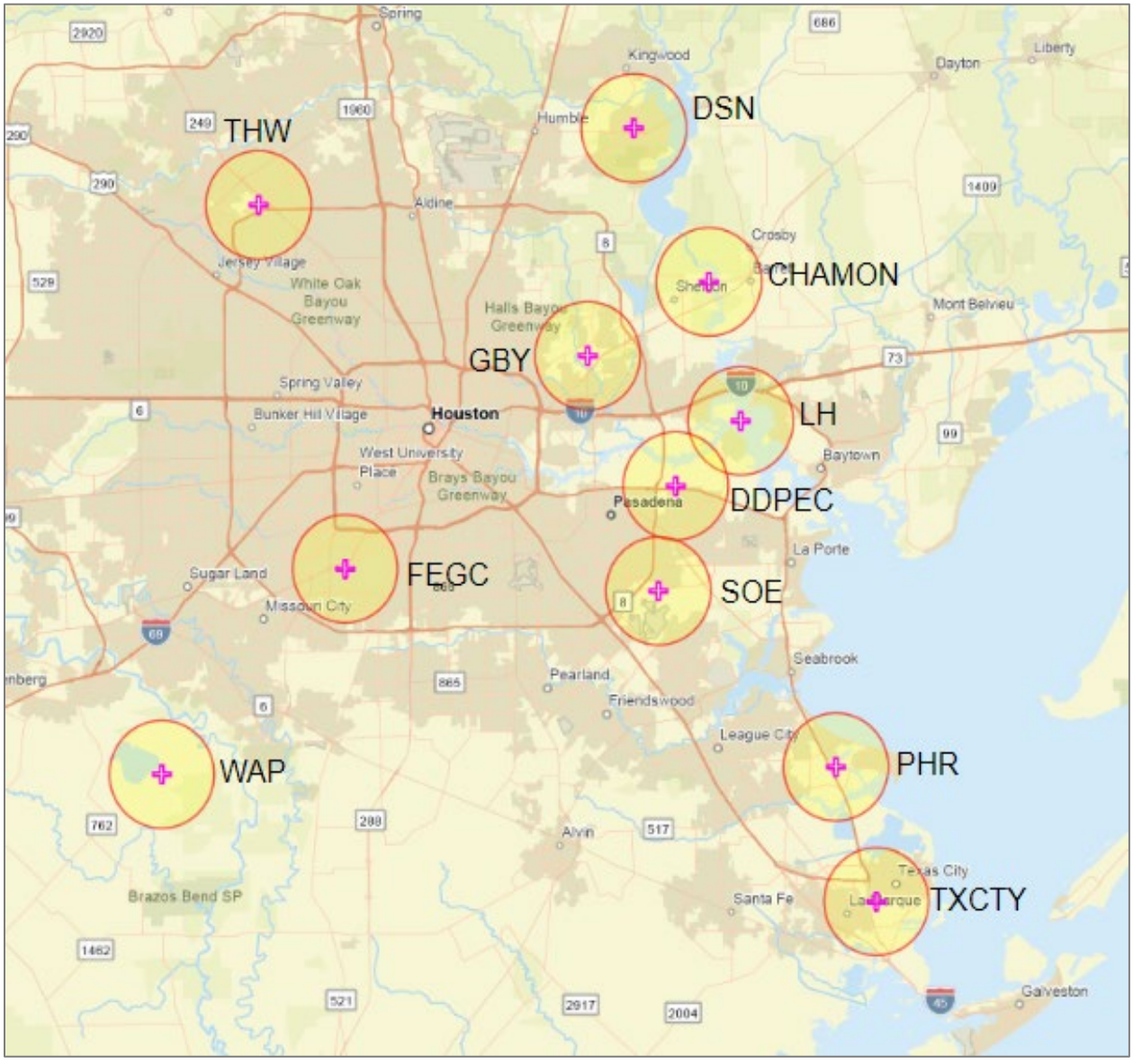
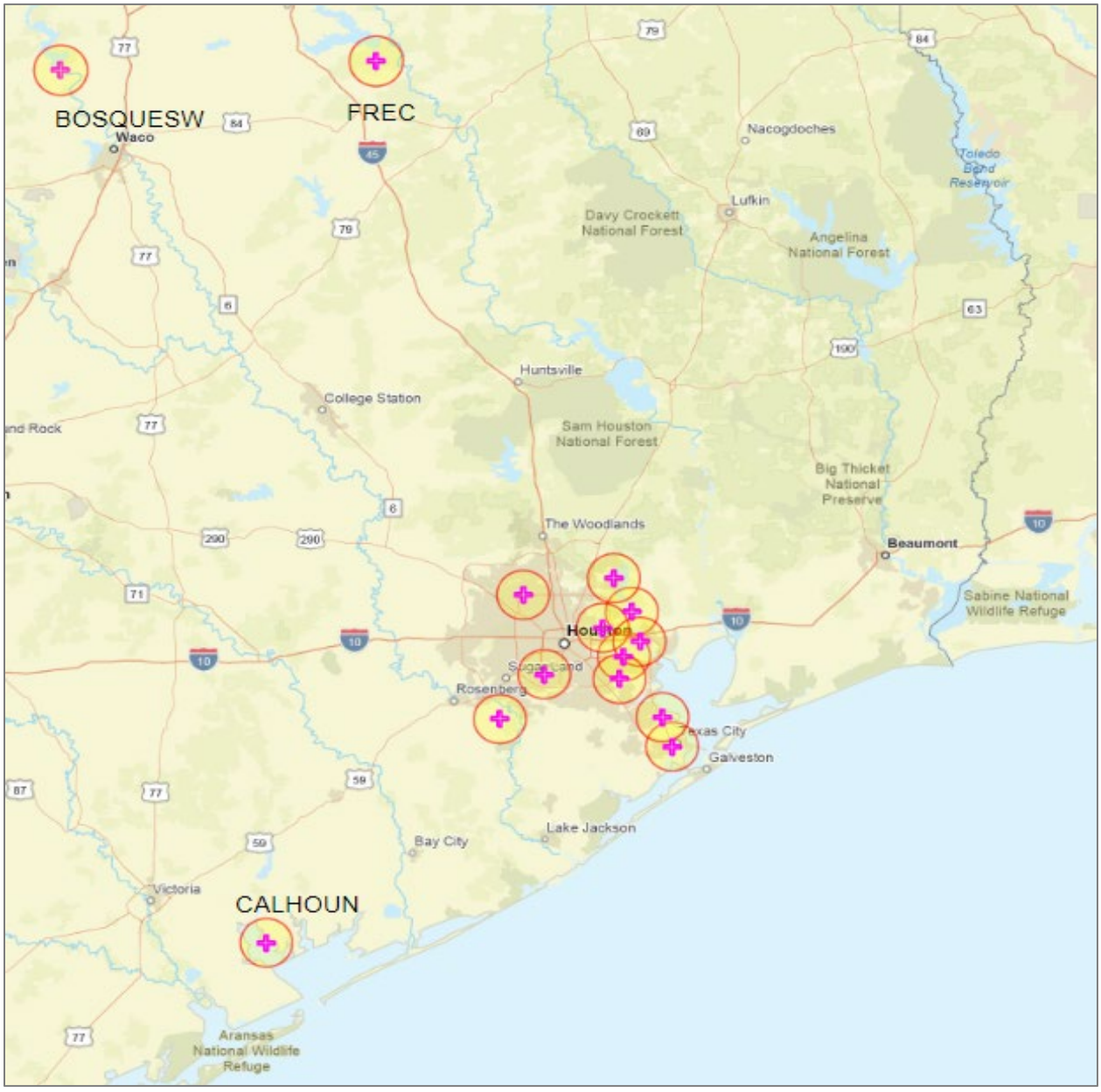


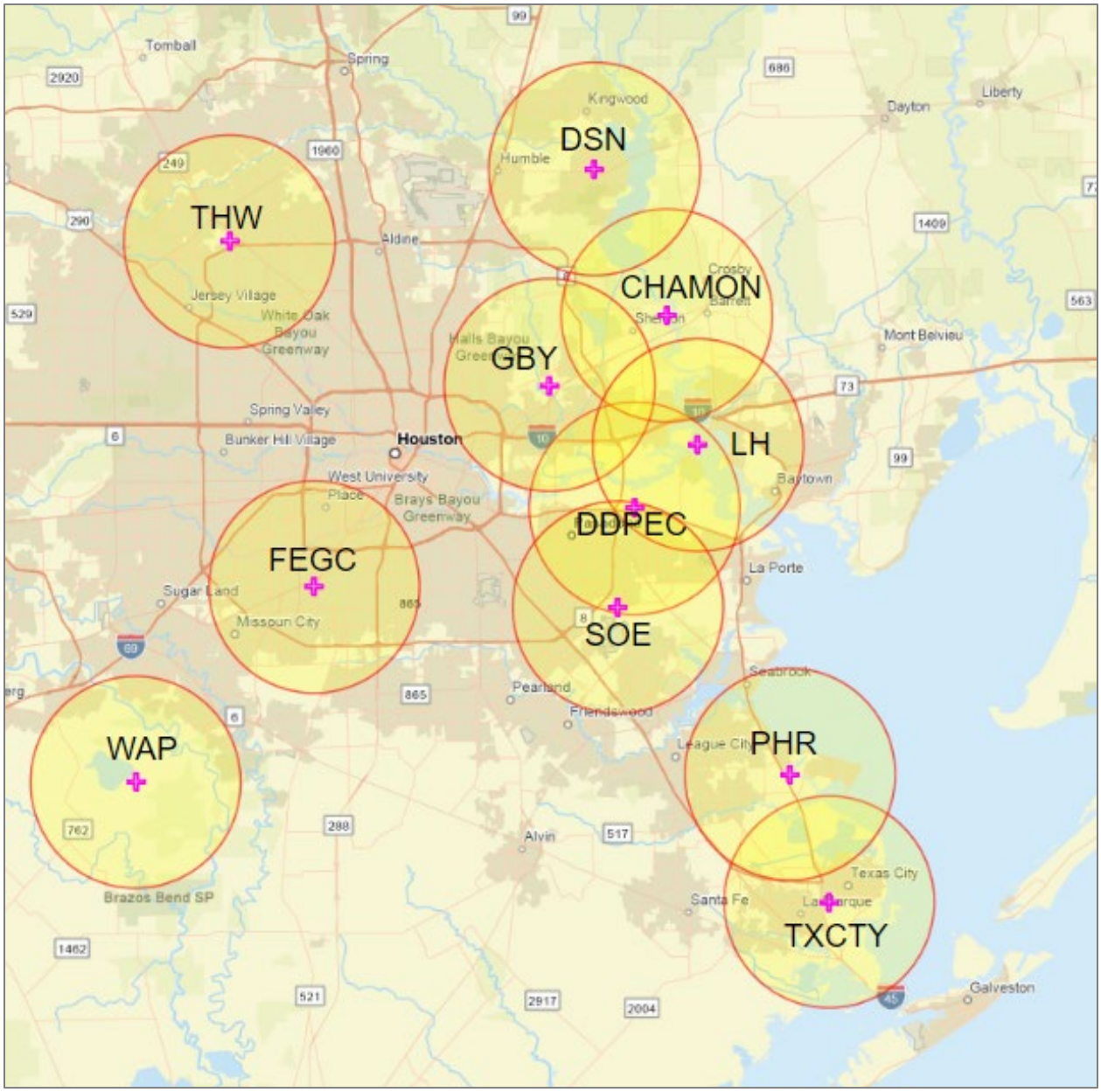
Figure 6 below overlays 10-km circles around the individual power plants. Using a 10-km radius around these plants captures a greater share of the potentially affected population and is consistent with the air quality analysis discussed above. It also creates more overlapping areas, which increases the EJ concerns for the people living in those areas. This is discussed in more detail below.

Figure 6. 10-km Radius Around Plants



Given the relative proximity of some of these plants, particularly those in the Houston area, several of the 10-km circles tended to have some overlapping areas among them, which suggests that some members of the population are likely to be affected by activities from multiple plants and are therefore exposed to higher EJ risks than others. In order to analyze those risks, Figure 7 below focuses on the plants around Houston to identify intersecting circles.

Figure 7. Intersecting Areas With 10-Km Radius Around the Plants



Using these custom boundaries, ICF extracted demographic and enviromental data from EJSCREEN to identify potential EJ vulnerabilities for the population living around these plants. Table 4 indicates the age ranges of populations in both the 5- and 10-km radii from the power plant indicated. As the table shows, there is a wide variablity of the exposure in the 5- and 10-km ranges around these plants. The total population exposed to any potential EJ concerns within a

5-km radius of these plants can range from about 50 people to over 100,000 people, with FREC being the lowest and FEGC being the highest. Similar patterns hold for the 10-km radii, except the range is from about 900 to over 500,000 people.

Table 4. Distribution of the Affected Population by Age

	5-Km Radius					10-Km Radius				
Power Plant	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**
BOSQUE	**1,989**	5%	12%	55%	29%	**4,176**	4%	13%	55%	28%
CALHOUN	**751**	10%	17%	65%	8%	**11,735**	7%	17%	59%	17%
CHAMON	**10,469**	6%	20%	60%	15%	**90,052**	9%	21%	62%	8%
DDPEC	**53,680**	7%	21%	61%	10%	**276,938**	8%	22%	61%	9%
DSN	**67,599**	8%	22%	61%	9%	**201,458**	7%	21%	61%	11%
FEGC	**112,417**	7%	18%	63%	12%	**568,858**	8%	18%	64%	10%
FREC	**56**	4%	20%	61%	16%	**868**	5%	16%	65%	14%
GBY	**79,700**	9%	21%	62%	8%	**258,116**	8%	22%	61%	9%
LH	**12,839**	9%	21%	57%	14%	**128,113**	8%	22%	61%	10%
PHR	**18,722**	9%	19%	62%	10%	**93,580**	8%	19%	61%	12%
SOE	**56,345**	6%	18%	63%	13%	**394,451**	8%	20%	62%	10%
THW	**107,393**	7%	20%	63%	10%	**461,570**	7%	20%	63%	10%
TXCTY	**43,452**	8%	19%	59%	15%	**71,729**	7%	18%	60%	16%
WAP	**745**	8%	20%	61%	11%	**54,391**	7%	23%	61%	10%

The majority of the people living in these areas seem to fall into what is likely the least vulnerable from an age perspective for EJ concerns. As the table above shows, more than 50 percent of the population falls within the 18–64 age group. However, some of these plants do have a relatively large share of the population that can be considered to be more susceptible to EJ problems. For example, BOSQUE has the highest percentage of people age 65+ in a 5- and 10-km radius, but is among the lowest in total population. Also, four of these plants have roughly 30 percent of the population below the age of 18, with about 20 percent or so in the 5–17 age group and the remaining 10 percent or so in the 0–4 age group.

Table 5 shows the distribution of the population by household incomes in both the 5- and 10-km radii. Note that the income data presented below are for households and not in per capita terms, which is different from how the data are shown in the other demographic tables.

Many of these plants have a relatively large share (20–30 percent) of the households that have incomes less than $25,000 or close to the federal poverty line. Among them, GBY and TXCTY have the highest percentage (13 percent for the 10-km radius) of people with incomes below $15,000 for a household, which is likely to exacerbate potential EJ concerns for this region. Correspondingly, GBY and TXCTY have the lowest percentage of people with a household income above $50,000, falling between 40 and 50 percent for both radii. This indicates that the majority of people in these radii have household incomes below $50,000, and both of these power plants are among those with a larger surrounding population.

Table 5. Distribution of the Affected Households by Income

	5-Km Radius					10-Km Radius				
Power Plant	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**
BOSQUE	**809**	10%	14%	23%	52%	**1,812**	11%	15%	22%	52%
CALHOUN	**285**	7%	7%	20%	65%	**4,137**	11%	8%	27%	53%
CHAMON	**3,418**	7%	8%	23%	62%	**28,248**	7%	7%	20%	66%
DDPEC	**16,779**	7%	9%	21%	63%	**85,473**	9%	10%	24%	56%
DSN	**22,212**	4%	4%	13%	78%	**67,417**	6%	5%	15%	74%
FEGC	**39,063**	11%	8%	21%	59%	**207,938**	12%	11%	22%	55%
FREC	**30**	10%	17%	17%	57%	**533**	10%	20%	19%	51%
GBY	**24,514**	11%	11%	30%	48%	**77,689**	13%	13%	30%	45%
LH	**4,234**	12%	10%	23%	55%	**39,892**	10%	9%	23%	59%
PHR	**6,527**	11%	12%	21%	56%	**34,256**	9%	8%	18%	64%
SOE	**19,748**	7%	7%	19%	68%	**130,051**	9%	8%	23%	60%
THW	**34,429**	7%	9%	25%	59%	**155,731**	8%	8%	24%	60%
TXCTY	**15,489**	15%	13%	30%	41%	**26,149**	13%	12%	27%	48%
WAP	**307**	2%	1%	9%	88%	**16,375**	3%	2%	8%	86%

The table below shows the breakdown of the population in these regions by race, in both the 5-km and 10-km radii. Race information is broken down to show populations that self-identify as Black, Hispanic, Other non-White (i.e., American Indian, non-Hispanic Asian, Pacific Islander, or another race), and White.

Not surprisingly, some of the regions with the lowest income distribution also have the largest minority populations. For example, the area around GBY, which had one of the largest shares of the low-income population, also has around 90 percent Black and Hispanic populations. TXCTY, which also had a high proportion of the low-income population around it, is about two-thirds Black and Hispanic. Among the others, the population around FEGC, THW, and LH is also high in non-White or minority populations.

Table 6. Distribution of Population by Race

	5-Km Radius					10-Km Radius				
Power Plant	**Total Population**	**Black**	**Hispanic**	**Other Non-white**	**White**	**Total Population**	**Black**	**Hispanic**	**Other Non-white**	**White**
BOSQUE	**1,989**	1%	7%	1%	91%	**4,176**	1%	7%	1%	90%
CALHOUN	**751**	5%	29%	9%	57%	**11,735**	4%	55%	7%	34%
CHAMON	**10,469**	21%	39%	3%	38%	**90,052**	18%	46%	4%	32%
DDPEC	**53,680**	2%	55%	2%	41%	**276,938**	4%	65%	2%	29%
DSN	**67,599**	17%	27%	6%	51%	**201,458**	15%	25%	5%	54%
FEGC	**112,417**	32%	39%	7%	22%	**568,858**	31%	35%	11%	23%
FREC	**56**	13%	7%	4%	77%	**868**	24%	7%	4%	65%
GBY	**79,700**	30%	59%	2%	9%	**258,116**	29%	61%	2%	9%
LH	**12,839**	7%	51%	3%	40%	**128,113**	14%	53%	4%	29%
PHR	**18,722**	4%	33%	7%	55%	**93,580**	9%	27%	5%	59%
SOE	**56,345**	3%	42%	10%	45%	**394,451**	6%	55%	7%	32%
THW	**107,393**	20%	40%	16%	24%	**461,570**	21%	39%	12%	29%
TXCTY	**43,452**	29%	32%	5%	34%	**71,729**	27%	29%	4%	40%
WAP	**745**	19%	22%	11%	48%	**54,391**	11%	13%	34%	41%

2.2 Combining Demographic Information With Environmental Indicators

In order to understand the EJ vulnerabilities of the population living around these power plants, we analyzed various pollutant indicators from EJSCREEN and used their estimated percentile rankings to compare the potential vulnerabilities across the various plants. The estimated percentile rankings, developed by EPA, combine the environmental indicator with the appropriate demographic data to account for the vulnerable groups in the calculation of the EJ indicator. In this context, EPA defines the vulnerable groups as the average of the count of minorities and low-income households. In terms of the individual percentile rankings, a low number signifies that this group is relatively better off than the rest of the state population, whereas a high ranking signifies a relatively worse off situation than the rest of the state. As an example, if a certain ranking is 80, it means that this place is at the 80th percentile, which implies that only 20 percent of the state population experiences pollution that is higher than those experienced by people in this region. Thus, as a general principal, percentile rankings that are on the high side generally imply the region in question is comparatively worse off than other places in the state.

Table 7 shows the relative rankings of the various populations around these plants that are exposed to the various environmental indicators of interest (see Table 7 notes for definitions of these pollutant indicators). We present the percentile rankings for both the 5- and 10-km radii around each power plant. Table 7 also presents a calculated average percentile ranking in order for us to easily compare across the various plants. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*). Note that these averages are simple arithmetic means, which essentially puts equal weights on each environmental indicator, irrespective of their implications on human health. Thus, one could argue that these averages are not reflective of the individual pollutants' effect on the vulnerable populations. We included them here for easy comparison across the groups without any value judgement on the individual pollutants.

Table 7. Percentile Ranking of Various Environmental Indicators

	5-Km Radius					
Power Plant	**Particulate Matter (PM 2.5 in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
BOSQUE	26	30	28	28	35	**29.4**
CALHOUN	40	38	40	40	50	**41.6**
CHAMON	57	59	69	62	60	**61.4***
DDPEC	52	62	64	54	85	**63.4***
DSN	16	16	12	15	25	**16.8**
FEGC	80	87	83	81	93	**84.8***
FREC	31	33	31	31	32	**31.6**
GBY	91	92	95	95	96	**93.8***
LH	62	67	84	68	95	**75.2***
PHR	41	40	40	40	49	**42**
SOE	44	51	50	46	66	**51.4***
THW	83	90	83	85	93	**86.8***
TXCTY	62	61	61	61	92	**67.4***
WAP	11	13	12	12	20	**13.6**
	10-Km Radius					
Power Plant	**Particulate Matter (PM 2.5 in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
BOSQUE	22	27	23	23	33	**25.6**
CALHOUN	51	48	48	47	46	**48**
CHAMON	81	80	94	87	94	**87.2***
DDPEC	70	77	85	79	95	**81.2***
DSN	30	32	28	30	50	**34**
FEGC	77	86	80	78	87	**81.6***
FREC	48	44	48	48	42	**46**
GBY	89	91	95	94	97	**93.2***
LH	78	80	92	87	96	**86.6***
PHR	31	26	26	30	58	**34.2**
SOE	66	75	77	69	86	**74.6***
THW	78	86	79	80	87	**82***
TXCTY	56	56	56	56	87	**62.2***
WAP	50	54	49	49	48	**50**

Particulate Matter ($PM_{2.5}$ in ug/m3) – $PM_{2.5}$ levels in the air, measured in µg/m3 annual average.

NATA Diesel PM (ug/m3) – Diesel particulate matter level in the air, measured in µg/m3.

NATA Air Toxics Cancer Risk (risk per MM) – Lifetime cancer risk from inhalation of air toxics.

NATA Respiratory Hazard Index – Air toxics respiratory hazard index (the ratio of exposure concentration to health-based reference concentration).

Hazardous Waste Proximity (facility count/km distance) – The count of hazardous waste facilities (TSDFs and LQGs) within 5 km (or nearest beyond 5 km), each divided by the distance in kilometers.

In order to identify which of these regions may have a vulnerable population exposed to disproportionately higher environmental justice concerns than the rest of the state, we chose an arbitrary 50-percent threshold and highlighted in the tables above those regions that are above that threshold. The results imply that the vulnerable populations living in these regions are experiencing higher levels of EJ concerns than a majority of the rest of Texas. Unsurprisingly, among these regions around power plants that are of higher EJ concerns, the ones that we identified above as having the most vulnerable populations are the ones with the highest average ranking. This includes populations around power plants GBY, FEGC, and THW as the most at-risk, with an average percentile ranking of over 80. Following those are SOE, LH, and TXCTY, with rankings between 60 and 70. Some power plants seem to jump considerably, moving from the 5-km to the 10-km radii. These include CHAMON and DDPEC, where the rankings jump from the 60s to 80s when we move from the 5-km to 10-km radius. Thus, when we analyze the vulnerable population within a 10-km radius of these plants, the majority of these power plants (i.e., 8 out of 14) have a baseline EJ vulnerability, higher than the rest of the state, affecting the population living near these power plants.

2.3 Population in Close Proximity to Multiple Plants

As discussed previously (see Figure 7), several of these power plants, particularly those around the Houston area, have significant overlapping regions when we analyze the populations within a 10-km radius around these plants. Populations living in these “intersecting circles” are likely to face even higher EJ concerns, given that they may have been exposed to higher emissions from multiple power plants. Here we present data for these population groups in these intersecting circles and their potential for higher EJ concerns.

Table 8 below shows the age distribution of the population living in these intersecting regions with two or more 10-km radii. The intersecting radii are of different sizes, which is part of the reason for the differences in population between areas. Overall, the percentage of people in each intersecting region that are between ages 0 and 4 are comparable to those 65+, with the latter only a slightly higher percentage in most areas. In total, approximately 12 percent, or about 325,000 of the 2.6 million total population living within a 10-km radius of all power plants, live in these intersecting regions and are thus likely to face higher levels of baseline EJ concerns than those that live outside of these intersecting regions. Most of this population group lives in an area that has two plants within 10 km, but about 20 percent of them live in areas that are close to three or more power plants.

Table 8. Distribution of the Affected Population in the Intersecting Regions by Age

	10-Km Radius Intersections				
Power Plants	**Total Population**	**0 to 4**	**5 to 17**	**18 to 64**	**65+**
CHAMON & DSN	**14,817**	10%	19%	65%	5%
GBY & CHAMON	**21,330**	10%	21%	63%	6%
GBY & DDPEC	**22,002**	9%	23%	60%	8%
LH & CHAMON	**11,605**	7%	20%	61%	12%
LH & DDPEC	**6,337**	10%	20%	60%	10%
LH & GBY	**1,073**	3%	22%	66%	10%
PHR & TXCTY	**8,678**	7%	17%	61%	16%
SOE & DDPEC	**175,158**	8%	21%	61%	10%
DDPEC & LH & GBY	**28,277**	8%	25%	59%	8%
GBY & LH & CHAMON	**10,371**	8%	25%	62%	6%
LH & DDPEC & CHAMON	**3,495**	9%	24%	56%	10%
LH & DDPEC & SOE	**15,072**	5%	19%	65%	11%
DDPEC & LH & GBY & CHAMON	**7,275**	7%	25%	62%	5%

Table 9 shows the household income of populations living in intersections of two or more 10-km radii. Household incomes for the intersecting regions are comparable to the incomes of the 5- and 10-km radii. Two intersecting areas have a majority of households with incomes less than $50,000, which are the LH/DDPEC/CHAMON intersection and the GBY/DDPEC intersection. Alternatively, the highest percentage of households with incomes over $50,000 is 81 percent, in the intersection of CHAMON and DSN.

Table 9. Distribution of the Affected Population in the Intersecting Regions by Income

	10-Km Radius Intersections				
Power Plants	**Total Households**	**< $15,000**	**$15,000–$25,000**	**$25,000–$50,000**	**$50,000 +**
CHAMON & DSN	**4,652**	3%	4%	12%	81%
GBY & CHAMON	**6,424**	4%	5%	26%	65%
GBY & DDPEC	**6,320**	12%	15%	29%	44%
LH & CHAMON	**3,972**	9%	11%	24%	56%
LH & DDPEC	**1,989**	11%	12%	24%	54%
LH & GBY	**281**	2%	2%	20%	76%
PHR & TXCTY	**3,095**	13%	9%	25%	53%
SOE & DDPEC	**55,947**	10%	10%	24%	57%
DDPEC & LH & GBY	**7,730**	7%	12%	29%	52%
GBY & LH & CHAMON	**2,873**	6%	3%	20%	71%
LH & DDPEC & CHAMON	**959**	13%	20%	21%	46%
LH & DDPEC & SOE	**4,917**	2%	5%	17%	75%
DDPEC & LH & GBY & CHAMON	**2,081**	8%	5%	20%	67%

Table 10 below shows the racial composition of the population living in intersections of two or more 10-km substation radii. Most of these intersecting regions have a predominantly minority population, with the Hispanic population comprising the bulk. The intersection with the highest total population is also among the highest in percentage of non-Whites, SOE/DDPEC. With a population over 100,000 greater than the next largest population, 69 percent of the population is either Black, Hispanic, or another non-White race. Other areas with a high percentage of non-White races are GBY/LH/CHAMON, DDPEC/LH/GBY/CHAMON, and LH/GBY.

Table 10. Distribution of the Affected Population in the Intersecting Regions by Race

	Race of Population				
	10-Km Radius Intersections				
Power Plants	**Total Population**	**Black**	**Hispanic**	**Other Non-White**	**White**
CHAMON & DSN	**14,817**	21%	28%	5%	46%
GBY & CHAMON	**21,330**	24%	54%	6%	16%
GBY & DDPEC	**22,002**	4%	82%	1%	13%
LH & CHAMON	**11,605**	7%	47%	1%	44%
LH & DDPEC	**6,337**	0%	56%	1%	43%
LH & GBY	**1,073**	37%	44%	7%	12%
PHR & TXCTY	**8,678**	19%	28%	4%	48%
SOE & DDPEC	**175,158**	2%	64%	3%	31%
DDPEC & LH & GBY	**28,277**	11%	72%	1%	16%
GBY & LH & CHAMON	**10,371**	22%	66%	3%	9%
LH & DDPEC & CHAMON	**3,495**	0%	67%	2%	31%
LH & DDPEC & SOE	**15,072**	0%	29%	6%	65%
DDPEC & LH & GBY & CHAMON	**7,275**	25%	65%	2%	9%

Table 11 below shows the EJ indexes in intersections of two or more 10-km substation radii. As discussed above, the environmental indicator listed in the Table 11 incorporates the value of the pollutant within the radius, as well as the percentage of minority people and low-income people in the radius. The table also presents the “average” percentile ranking as a way to ordinally rank these intersecting circles. Average percentile rankings greater than 50 percent are highlighted in light blue and indicated with an asterisk (*).

Table 11. Environmental Justice Index in State Percentiles for People Living in the Intersecting Points of Two or More Substations in a 10-km Radius

	10-Km Radius Intersections					
Power Plants	**Particulate Matter (PM 2.5 in ug/m3)**	**NATA Diesel PM (ug/m3)**	**NATA Air Toxics Cancer Risk (risk per MM)**	**NATA Respiratory Hazard Index**	**Hazardous Waste Proximity (facility count/km distance)**	**Average Percentile Ranking**
CHAMON & DSN	42	44	43	43	41	**42.6**
GBY & CHAMON	94	93	97	96	94	**94.8***
GBY & DDPEC	78	85	89	94	98	**88.8***
LH & CHAMON	54	60	71	59	75	**63.8***
LH & DDPEC	64	69	90	72	97	**78.4***
LH & GBY	68	73	81	79	94	**79***
PHR & TXCTY	65	62	65	63	87	**68.4***
SOE & DDPEC	64	74	78	68	92	**75.2***
DDPEC & LH & GBY	88	89	97	96	99	**93.8***
GBY & LH & CHAMON	96	95	99	98	99	**97.4***
LH & DDPEC & CHAMON	78	80	97	84	98	**87.4***
LH & DDPEC & SOE	13	10	2	10	0	**7**
DDPEC & LH & GBY & CHAMON	95	93	99	97	99	**96.6***

Using the same 50 percent threshold, the table shows which of these intersecting circles have a value higher than 50 percent, which implies that the population living in these intersecting regions have a higher level of exposure to EJ concerns than a majority of the rest of the population in Texas. Only two intersections have an average state percentile under 50 percent, which are LH/DDPEC/SOE and CHAMON/DSN. Thus, almost 85 percent of the population living in these intersecting regions have higher exposure to EJ concerns than the rest of the state. Given that these population groups, consisting mostly of minority populations, live near multiple power plants (and presumably other stationary sources), it is not surprising that these groups are more vulnerable when it comes to environmental justice considerations compared to the rest of the state.

2.4 Conclusion – Environmental Justice Analysis

Using data from EPA's EJSCREEN, it appears that people of color and those with limited socioeconomic means in and around the Houston area are more vulnerable to environmental justice considerations compared to the rest of Texas. Given the paucity of data discussed in the air quality analysis above, we could not determine whether the EJ concerns for these groups were exacerbated during those 5 days in February 2021, when DOE authorized the emergency use of power generation under Section 202(c) of the Federal Power Act. However, analyzing the *baseline, business-as-usual* EJ concerns for the population around these power plants does indicate that a majority of the population living here are minority with limited socioeconomic opportunities and that they are also vulnerable to higher levels of pollution under those baseline conditions.

3 References

U.S. Environmental Protection Agency. 1972. *Mixing Heights, Wind Speeds, and Potential for the Urban Air Pollution Throughout the Contiguous Unites States*. Prepared by George Holzworth. Research Triangle Park, NC: Office of Air Program, AP-101.

Appendix – Generators

Generator Name	Fuel Type	Resource Owner Name	County	Unit Code
East Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	CL_EWP_30UNITS
Lynchburg Pump Station	Distillate Fuel Oil	NRG Energy Services	Harris	LH_LYN_30UNITS
Northeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	DSN_NEWP_10UNITS
Southeast Water Plant	Distillate Fuel Oil	NRG Energy Services	Harris	SOE_SEWP_10UNITS
Clear Lake City WWTP	Distillate Fuel Oil	NRG Energy Services	Harris	PHR_CLCWA_5UNITS
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 1	Natural Gas	Calpine Corporation	Freestone	FREC_CC2
W. A. Parish G4	Natural Gas	NRG Energy Services	Fort Bend	WAP_WAP_G4
T. H. Wharton GT54	Natural Gas	NRG Energy Services	Harris	THW_THWGT54
T. H. Wharton GT56	Natural Gas	NRG Energy Services	Harris	THW_THWGT56
Deer Park Energy Center	Natural Gas	Calpine Corporation	Harris	DDPEC_CC1
Texas City Power Plant	Natural Gas	Calpine Corporation	Galveston	TXCTY_CC1
Freestone Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	FREC_CC2
Bosque Energy Center Block 1	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC1
Bosque Energy Center Block 2	Natural Gas	Calpine Corporation	Bosque	BOSQUESW_CC2
Chamon CT1	Natural Gas	Chamon Power LLC	Harris	CHAMON_CTG_0101
Chamon CT2	Natural Gas	Port Comfort Power LLC	Harris	CHAMON_CTG_0301
Port Comfort CT1	Natural Gas	Chamon Power LLC	Calhoun	CALHOUN_UNIT1
Port Comfort CT2	Natural Gas	Port Comfort Power LLC	Calhoun	CALHOUN_UNIT2
Friendswood Energy Genco	Natural Gas	Friendswood Energy Genco LLC	Harris	FEGC_UNIT1

Source: “ERCOT_DOE_202(c)_Exhibit_A_2-17-2021_2100,” ERCOT.