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August 24, 2021

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 48917

Dear Ms. Felice:

Re: MPSC Case No. U-20530

Enclosed find the ***Attorney General's PUBLIC Testimony and Exhibits of Devi Glick,*** and related Proof of Service.

Sincerely,

Michael Moody

Digitally signed by Michael Moody
Date: 2021.08.24 13:43:19 -04'00'

Michael E. Moody
Assistant Attorney General

cc: All Parties

PROOF OF SERVICE - U-20530

The undersigned certifies that a copy of the ***Attorney General's PUBLIC Testimony and Exhibits of Devi Glick*** was served upon the parties listed below by e-mailing the same to them at their respective e-mail addresses on the 24th day of August 2021.

Michael Moody Digitally signed by Michael Moody Date: 2021.08.24 13:44:08 -04'00'

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of INDIANA MICHIGAN POWER COMPANY for a Power Supply Cost Recovery Reconciliation proceeding for the 12-month period ended December 31, 2020.	)))))	**Case No. U-20530**

Direct Testimony of Devi Glick

On Behalf of the Attorney General of Michigan

Public Version

August 24, 2021

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name and occupation.

A My name is Devi Glick. I am a Principal Associate at Synapse Energy Economics, Inc. My business address is 485 Massachusetts Avenue, Suite 3, Cambridge, Massachusetts 02139.

Q Please describe Synapse Energy Economics.

A Synapse is a research and consulting firm specializing in energy and environmental issues, including electric generation, transmission and distribution system reliability, ratemaking and rate design, electric industry restructuring and market power, electricity market prices, stranded costs, efficiency, renewable energy, environmental quality, and nuclear power.

Synapse's clients include state consumer advocates, public utilities commission staff, attorneys general, environmental organizations, federal government agencies, and utilities.

Q Please summarize your work experience and educational background.

A At Synapse, I conduct economic analysis and write testimony and publications that focus on a variety of issues related to electric utilities. These issues include power plant economics, utility resource planning practices, valuation of distributed energy resources, and utility handling of coal combustion residuals waste. I have submitted expert testimony on unit commitment practices, plant economics, utility resource needs, and solar valuation before state utility regulators in Michigan, Arizona, Connecticut, Florida, Indiana, Nevada, New Mexico, North Carolina, South Carolina, Texas, Virginia, and Wisconsin. In the course of my work, I develop in-house electricity system models and perform analysis using industry-standard electricity system models.

Before joining Synapse, I worked at Rocky Mountain Institute, focusing on a wide range of energy and electricity issues. I have a master's degree in public policy and a master's degree in environmental science from the University of Michigan, as well as a bachelor's degree in environmental studies from Middlebury College. I have more than eight years of professional experience as a consultant, researcher, and analyst. A copy of my current resume is attached as Exhibit AG-1.

Q On whose behalf are you testifying in this case?

A I am testifying on behalf of Dana Nessel, Attorney General of Michigan.

Q Have you testified previously before the Michigan Public Service Commission ("Commission")?

A Yes, I submitted testimony in Case No. 20224, the 2019 Indiana Michigan Power Company's ("I&M" or "Company") Power Supply and Cost Recovery ("PSCR") reconciliation docket and in Case No. 20804, the Company's PSCR plan for 2021.

Q What is the purpose of your testimony in this proceeding?

A In my testimony for this proceeding, I evaluate three subjects: First, I evaluate the Company's request to include in its reconciliation of recoverable PSCR expenses amounts paid to the Ohio Valley Electric Corporation ("OVEC") in 2020 for power from the OVEC units under the Inter-Company Power Agreement ("ICPA"). Second, I evaluate I&M's request to include amounts paid to AEP Generation ("AEG") in 2020 for power from a portion of AEG's owned share of

Rockport Unit 1 and a portion of AEG's leased share of Rockport Unit 2. Third, I review the fuel and power purchase costs for I&M's owned share of the Rockport units that it plans to pass on to customers for 2020.

Q How is your testimony structured?

A In Section 2, I summarize my findings and recommendations for the Commission.

In Section 3, I discuss how I&M customers paid unreasonable prices, significantly above market, to OVEC for power under the ICPA in 2020. I present several different metrics that can be used to value the services provided under the ICPA. I present evidence of OVEC's uneconomic operational practices that are driving the significant losses at the units. I also outline my recommendations to the Commission to disallow recovery of ICPA costs above market value.

In Section 4, I discuss how I&M customers paid unreasonable prices in 2020, far above market, for the portion of Rockport's power that it purchased from AEG through a power purchase agreement ("PPA"). I explain how the Commission, in I&M's PSCR plan case for 2018, directed the Company to take actions to address the costs of the AEG contract, but I&M failed to take any such actions. I also outline my recommendations to the Commission to disallow recovery of ICPA costs above market value.

In Section 5, I summarize the actual performance of Rockport during 2020 and I calculate the costs that uneconomic commitment practices will impose on ratepayers if approved for recovery in this proceeding. I discuss how I&M is imprudently operating the Rockport units and passing the excess costs on to its ratepayers. I recommend that the Commission disallow recovery of excess fuel costs incurred at the Rockport unit based on the Company's uneconomic unit commitment[1] practices.

Q What documents do you rely upon for your analysis, findings, and observations?

A My analysis relies primarily upon the workpapers, exhibits, and discovery responses of I&M witnesses associated with this proceeding, as well as discovery from other proceedings where applicable. I also rely on public information associated with prior I&M proceedings. To a limited extent, I also rely on certain external, publicly available documents such as State of the Market reports for PJM.

2. Findings and Recommendations

Q Please summarize your findings.

A My primary findings are:

1. I&M has been purchasing power from OVEC, an affiliate company, at above-market value and passing those costs on to customers. Over the course of 2020, the ICPA cost I&M customers $26.5 million more than the cost of equivalent energy and capacity purchased from the market, and more than the cost of other available benchmarks.

2. OVEC currently operates its two power plants, Clifty Creek and Kyger Creek, uneconomically and incurs net losses relative to market energy

[1] In my testimony, I will use the term "unit commitment" to refer to the decision made by the utility or the market on whether to operate a unit at its minimum operating level and therefore make it available to the market. I will use the term "unit dispatch" to refer to the decision by the utility or the market on how to operate a unit above its minimum operating level once the unit has been committed online.

prices. In 2020, I&M ratepayers incurred $2.3 million in losses relative to the energy market on just a variable cost basis (out of the total $26.5 million in excess costs incurred). In 2020, I&M customers would have been better off if the OVEC plants had not operated at all. These losses could be mitigated with more prudent unit commitment practices.

3. I&M paid its affiliate AEG for a portion of AEG's share of the Rockport units at a cost that was far in excess of market value. Over the course of 2020, the Unit Power Agreement ("UPA") cost I&M customers $115.1 million more than the cost of equivalent energy and capacity purchased from the market; and more than the cost of other available benchmarks.

4. I&M regularly self-commits Rockport Units 1 and 2. In 2020, the Company self-committed Rockport Unit 1 and 2 despite projecting net operational losses from committing the units as must-run in 7 out of 8 operational months at Rockport 1 and for 5 out of 6 operational months at Rockport 2.

5. I&M incurred an avoidable [redacted] in net losses relative to the market over six distinct periods where the Company self-committed a Rockport unit with a must-run status despite its own 6-day forecasts projecting that net revenue losses would result from the decision to self-commit the unit.

6. In total, I&M incurred net losses relative to market energy prices of [redacted] at Rockport in 2020 on a variable cost basis; [redacted] of those losses will become the direct responsibility of I&M customers. The majority of these losses are attributed to the six distinct periods, which all could have been mitigated with more prudent unit commitment practices.

Q Please summarize your recommendations.

A Based on my findings, I offer the following chief recommendations:

1. The Commission should disallow in this proceeding $3.7 Million, which is Michigan's jurisdictional share of the total $26.5 million in excess

compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in 2020.

2. The Commission should disallow in this proceeding $16.1 million, which is Michigan's jurisdictional share of the total $115.1 million in excess compensation that I&M paid AEG for power from Rockport services under the UPA (relative to the market value of the services).

3. The Commission should disallow in this proceeding [redacted], which represents I&M's ownership share (50 percent) of Michigan's jurisdictional share of the [redacted] in fuel costs out of the [[[redacted]] in unnecessary variable costs incurred at Rockport as a result of I&M's uneconomic unit commitment practices. These losses were avoidable if I&M had followed the results of its own price-based process and therefore should not be passed on to ratepayers.

3. I&M CUSTOMERS ARE PAYING UNREASONABLE PRICES TO OVEC FOR POWER UNDER THE ICPA

i. I&M purchases power from OVEC under the ICPA

Q What is OVEC and how is it related to I&M ratepayers?

A OVEC is jointly owned by 12 utilities in Ohio, Indiana, Michigan, Kentucky, West Virginia, and Virginia. OVEC operates two 1950s-era coal-fired power plants— (1) Kyger Creek, a five-unit, 1,086 MW plant in Gallia County, Ohio, and (2) Clifty Creek, a six-unit, 1,303 MW plant, in Jefferson County, Indiana. The Company supplies the power from these plants to the utilities through a long-term contract called the Inter-Company Power Agreement (ICPA).[2] Together, the utilities are responsible for the fixed and variable costs of OVEC. In turn, OVEC bills the utilities a variable, demand, and transmission charge. The Michigan Public Service Commission has found that OVEC is an affiliate of I&M.[3]

Q What portion of OVEC is I&M responsible for?

A I&M's share of the ICPA with OVEC is 7.85 percent.[4] This means that I&M is responsible for 7.85 percent of OVEC's fixed and variable costs while also being entitled to a 7.85 percent share of OVEC's power output. This translates into an installed capacity ("ICAP") share of 174–174.3 MW. The cost of the ICPA is passed through to I&M ratepayers as a direct cost.

Q Has I&M ever sought or received approval from the Commission for its decision to sign the ICPA?

A No. The Commission has found that the ICPA was not approved by the Commission, nor were the 2004 and 2010 amendments, which resulted in extending the ICPA through 2040.[5] The Clifty Creek and Kyger Creek Plants will each be 85 years old by the time the ICPA expires in 2040.[6]

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[2] Ex AG-2, Ohio Valley Electric Corporation, Annual Report – 2019 (p. 1).
[3] Commission Order dated May 13, 2021 in Case No. U-20529, Page 17.
[4] *Id.*
[5] Commission Order in Case No. U-20529, Page 13.
[6] Ex AG-2, p. 1.

ii. ***<u>I&M pays above-market prices for the power it purchases from OVEC and passes the excess costs on to its customers</u>***

Q How does I&M serve customer load, and which associated costs are at issue in this reconciliation docket?

A I&M serves customer load through three types of resources: (1) generation assets owned (or leased) and operated by the Company, (2) power purchased under PPAs from generation assets owned by other entities or affiliates, and (3) PJM market power purchases.

For units owned or leased by I&M, the fuel costs associated with running the units are forecasted in PSCR dockets, recovered via the PSCR factor, and then reconciled in reconciliation dockets such as this one. All other operational costs are the subject of separate proceedings such as rate cases. For power purchased under PPAs, PSCR dockets serve to forecast the entire cost—rather than just the fuel costs—to operate the units generating the power. This cost is recovered directly from customers via the PSCR factor and then reconciled in reconciliation dockets such as this one.

Q What does it mean that I&M is paying OVEC above-market prices for power?

If I&M can purchase the energy, capacity, or ancillary services that it needs from the PJM market at a lower cost than it would pay to purchase power from OVEC under the ICPA, then it is paying above the market price for the OVEC power.

Q Considering only variable charges and energy market revenue, is the ICPA delivering net revenues to I&M ratepayer?

A No. I compared just the energy charges billed to Sponsoring Companies[7] under the ICPA and the revenue that I&M earned selling that energy into the PJM energy market. I&M's own data shows that in 2020 OVEC billed I&M $18,487,826 in energy charges for 721,476 MWh of electricity.[8] That works out to an energy cost of $25.63/MWh. But I&M only earned $15,960,650 in energy and ancillary market revenue selling that energy, which works out to a value of $22.12/MWh.[9] That means that on a marginal cost basis alone, in 2020 I&M lost $2.3 million for its ratepayers (excluding demand charge and capacity value). Another I&M discovery response provides net energy revenues for the year of negative $2,571,839.[10]

Q Is the ICPA delivering value to I&M ratepayers based on the total value of its provided services?

A No. I compared the total cost billed to members of the ICPA by adding demand and transmission charges to the energy charges I already reviewed. I compared this cost to the value of the energy, capacity, and ancillary services provided by OVEC if I&M sold those services into the PJM. Exhibit IM-4, page 3 line 13 states that OVEC charged I&M $47,225,819 for 721,475 MWh in 2020, for an average cost of $65.46 per MWh. A discovery response to Staff shows that in

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[7] The owners of OVEC and their utility-company affiliates are considered Sponsoring Companies. Sponsoring Companies are each either a shareholder in the Company or an affiliate of a Shareholder in the Company, with the exception of Energy Harbor Corp.

[8] Ex AG-3, I&M Response to Staff Request 2-04, Attachment 1.

[9] Ex AG-4, I&M Response to Attorney General Request 3-44, Attachment 1.

[10] Ex AG-5, I&M Response to Attorney General Request 1-07, Attachment 1.

2020 OVEC billed I&M a total of $47,665,070 for 721,476 MWh.[11] That works out to a higher cost of $66.07/MWh.

In contrast, the value of the market revenue that would be generated in PJM for OVEC's energy, capacity, and ancillary services was equivalent to only $29.38/MWh for I&M.[12] This is well below the cost OVEC is charging I&M.

That amounts to a net loss of $26.5 million in 2020 that I&M customers are being asked to pay while receiving no additional value. In Figure 1 below, I show the all-in monthly cost of OVEC's services relative to the value the services are providing to I&M ratepayers. In each month of 2020, I&M ratepayers were paying significantly more for OVEC services than the equivalent market value of the services.

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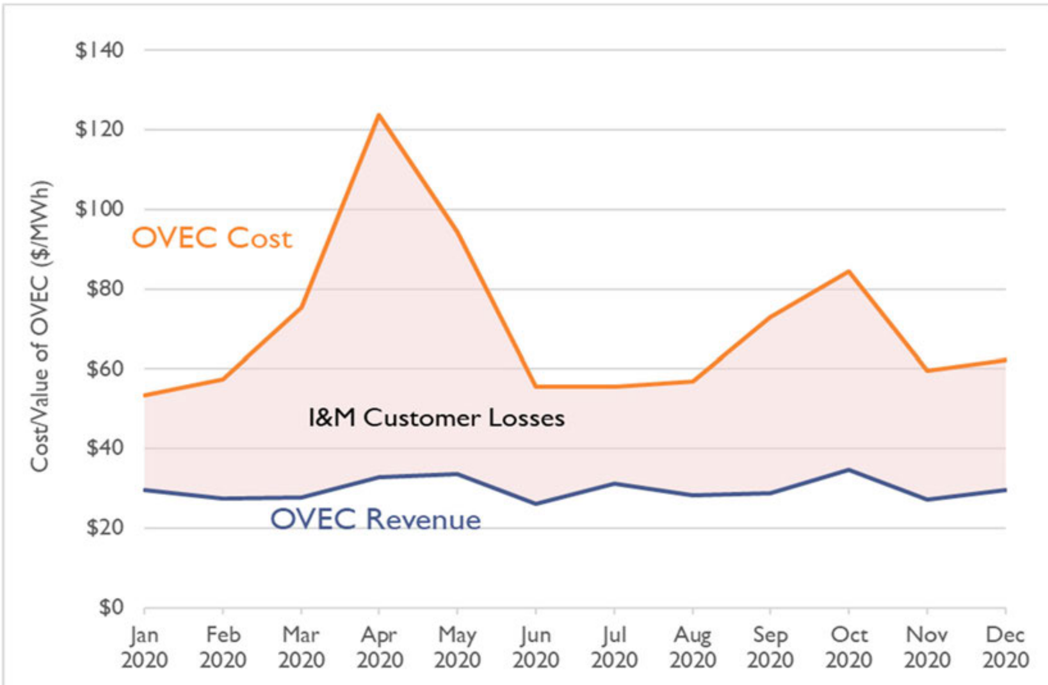
[11] *Id*.

[12] Ex AG-4 and Ex AG-26, page 302-303.

Figure 1: All-in OVEC cost / value for energy, ancillary services, and capacity (2020)



Source: I&M Response to Attorney General 3-44, AG 3.44 Attachment 1; and Ex AG-26, State of the Market Report for PJM, January through September (2020), pages 302-303.

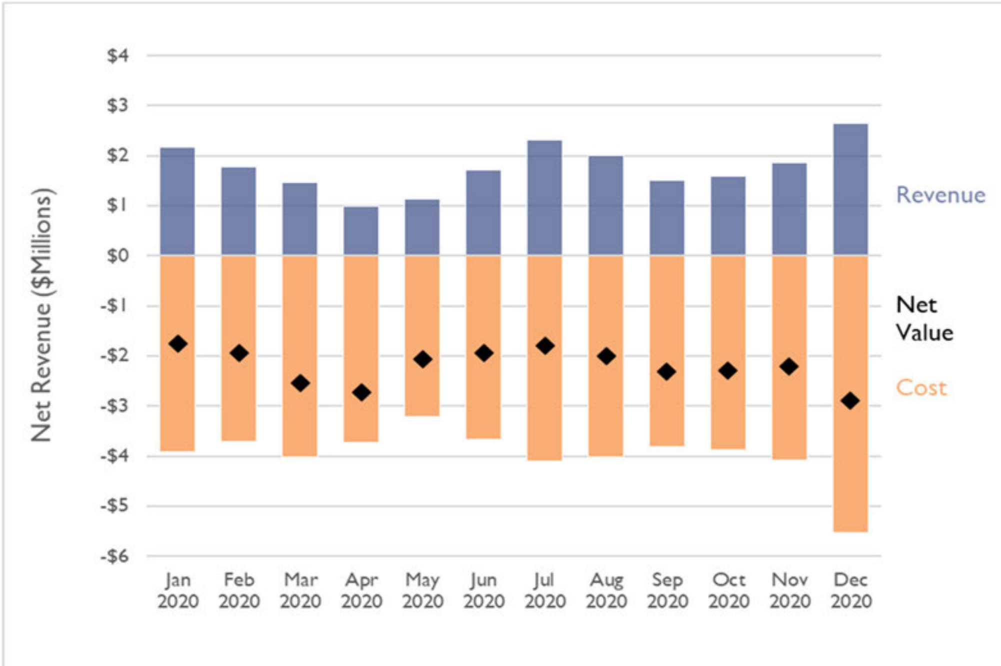
Q How do you calculate the cost to ratepayers of OVEC's contract?

A I&M provided the monthly billing from OVEC for 2020 which includes MWh sold, energy, demand, and transmission charges, along with PJM expenses and fees.[13] The Company provided energy and ancillary revenue by month.[14] Using the ICAP values for 2021 (174 MW in January–May, and 174.3 MW June–December),[15] I estimated a capacity value based on the value that I&M's share of OVEC capacity would receive in the PJM Base Residual Auction (BRA).

[13] Ex AG-3.
[14] Ex AG-4.
[15] Ex AG-6, I&M Response to Sierra Club Request 4.7, Case No. U-20804.

To find the net value or cost to ratepayers of the ICPA, I assumed the cost of the OVEC contract was equivalent to the monthly billing from OVEC. I assumed the value of the ICPA would be equal to the sum of the energy, ancillary services, and capacity value, with the later calculated as if OVEC's capacity were sold under the BRA. Figure 2 below shows the monthly OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity for 2020. In every month, I&M customers were billed substantially more for OVEC power than I&M would have received from the PJM market for OVEC's equivalent levels of capacity, energy, and ancillary services.

Figure 2: OVEC billing versus I&M revenue from ICPA energy, ancillary services, and capacity (2020)



Source: I&M Response to Staff Request 2-04, Staff 2-04 Attachment 1; I&M Response to Attorney General Request 3-44, AG 3-44 Attachment 1; and Ex A-26, pages 302-303.

Q What do you conclude with respect to the ICPA and the services that I&M ratepayers receive from the contract?

A Based on I&M's own data I find that under the ICPA, in 2020 alone, the energy charges under the ICPA cost I&M customers $2.3 million more than the market value of energy, while the total billed charges (inclusive of energy, capacity, transmission, and other charges) cost I&M customers $26.5 million more than the market price for the same amount of energy and capacity. This means that even with the demand-charge locked in, ratepayers would have been better off if the plant had not operated in 2020 and I&M instead purchased energy from the market.

iii. A reasonable price to pay for power under the ICPA should be measured based on the cost billed for similar services or the cost of replacement resources

Q Has I&M provided any comparators for the value of the energy and capacity provided by OVEC?

A No. The Attorney General submitted six discovery questions asking the Company for the following: (1) any valuations it has taken for fixed resource requirement (FRR) capacity; (2) any comparisons or evaluations that I&M had performed to benchmark the cost of capacity it gets under the ICPA; (3) RFP bid results; (4) unsolicited capacity offers; and (5) capacity purchases the Company had made in the recent past. The Company refused to provide any data or information that could be used as a long-term supply option to compare with the costs it pays to OVEC.[16] By refusing to do so, the Company has left it to the Commission to determine an appropriate benchmark.

Q What metrics can be used to benchmark the value of capacity and energy provided by the OVEC units?

A There are several long-term supply comparisons we can use to evaluate whether the costs charged under the ICPA are reasonable and compliant with the MPSC Code of Conduct: These include: (1) The costs billed or paid by other entities for similar services provided under long-term PPAs; (2) the cost of replacement capacity resources as represented by Cost of New Entry (CONE); (3) The cost of replacement capacity and energy resources as represented by responses to requests for proposals (RFP) and other Company information; (4) and the PJM

[16] Ex AG-7: I&M Responses to AG 1-06, AG 1-08. AG 1-12, AG 1-13, AG 1-14, and AG 1-15.

short-term capacity and energy market. Table 1 below summarizes the alternative benchmarks discussed in this section on a $/MWh basis and calculates the total excess costs incurred under the ICPA relative to each benchmark.

Table 1: OVEC cost benchmarks

	$/MWh	Excess costs based on benchmark ($ Million)
OVEC PSCR cost[1]	$65.46	NA
Cost of similar services		
MPPA billing from Consumers Energy for Campbell Unit 3[2]	$28.87	$ 26.4
MPPA billing from DTE for Belle River[3]	$55.16	$ 7.4
Consumers PPA expense for MCV[4]	$48.89	$ 12.0
Value of CONE & PJM BRA		
CONE – combined cycle plant[5]	$50.32	$ 10.9
CONE – combustion turbine[5]	$48.03	$ 12.6
PJM base residual auction (BRA)[6]	$29.38	$ 26.0
Replacement resource PPA prices		
I&M renewable RFP results (average)[7]		
Medium solar	$50.00	$ 11.2
Large solar	$44.00	$ 15.5
Wind	$45.00	$ 14.8
NIPSCO RFP Results[8]		
Solar PV	$39.30	$ 18.9
Solar PV + battery storage	$43.30	$ 16.0
Wind	$37.10	$20.5

Sources: [1]Exhibit IM-4 (JEW-1), (p.3); [2] Ex AG-8, DTE billing statements to MPPA for Bell River Power in 2020; Ex AG-9, DTE Response to MEC Request 4.1 in Case No. U-20528; [3] Ex AG-10, Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2020; Ex AG-11, Consumers Response to MEC Request 1.9 in Case No. U-21090; [4]Ex AG-12, Exhibit A-17 (JLR-1) in Case No U-20526; [5] Ex AG-13, PJM, Default MOPR Floor Offer Prices for New Generation Capacity Resources. March 11, 2020; [6] Ex AG-3; Ex AG-4; Ex AG-26, State of the Market Report for PJM, January through September (2020) pages 302-303; [7] Ex AG-14, Indiana Michigan

Power: 2021 Integrated Resource Plan, Public Stakeholder Meeting #3A, July 27, 2021; [8] Ex AG-15, NIPSCO's 2019 Request for Proposals Results, February 18, 2020.

Q How does the cost of power under the ICPA compare to the billed costs for other similar PPAs?

A The cost of power under the ICPA is much higher than the cost paid for power under several similar PPAs in the region. I reviewed Michigan Public Power Agency (MPPA) billing statements from DTE for Belle River[17] and from Consumers for J.H. Campbell 3[18] and calculated the average cost billed for power charged for each unit. I find that in 2020, Consumers Energy billed MPPA an average of $28.87/MWh for power purchased from J.H. Campbell 3[19] and DTE billed MPPA an average of $55.16 for the power purchased from Belle River. These charges covered the construction, fuel, and operations and maintenance ("O&M") expenses from similar thermal resources and provided both energy and capacity to MPPA.

I also reviewed Consumers' purchased power costs and found that in 2020 Consumers paid $48.89/MWh for power from Michigan Cogeneration Venture

[17] Ex AG-8, DTE billing statements to MPPA for Bell River Power in 2020 obtained under FOIA. Calculations based on total expenses before adjustments. Generation from Ex AG-9, DTE Response to MEC Request 4.1, Docket U-20528.

[18] Ex AG-10, Consumers billing statements to MPPA for JH Campbell Unit 3 Power in 2020 obtained under FOIA. Calculations based on expenses before adjustments. Generation from Ex AG-11, Consumers Response to MEC Request 1.9, Docket No. U21090.

[19] The billing data provided by Consumers in Ex AG-11 was different than the cost data provided in the individual monthly bills sent by Consumers to MPPA. The average cost of $29.03/MWh in 2020.

(MCV).[20] MCV is a natural gas-fired electrical and steam co-generation plant located in Midland, Michigan.

Q What is CONE and how does the value of CONE compare to the cost paid under the ICPA?

A CONE is a conservative measure of value that represents the cost of building new gas-fired generation capacity. If I&M were capacity constrained, as it projects it will be starting in 2023,[21] the capacity portion of the ICPA could be valued at PJM's CONE. The PJM value of CONE for a new combined cycle unit is $320/MW-Day and for a new combustion turbine unit it is $294/MW-Day.[22] This works out to a total value of $50.32/MWh and $49.03/MWh when Rockport's AEG power is valued based on CONE of a new combined cycle unit and combustion turbine respectively.

I arrived at these values by multiplying the $/MW-Day CONE values by the 174 MW of capacity that I&M purchases as part of the PPA with AEG and then multiplying that by 365 days in a year. I then added the energy and ancillary revenues that I&M received for the AEG portion of Rockport from the PJM market to find the total value of the power purchased from AEG. Finally, I divided that total value of the power by the MWh of generation purchased from AEG to find the total $/MWh.

[20] Ex AG-12, Exhibit A-17 (JLR-1), Case No U-20526.

[21] Ex AG-16, I&M Exhibit IM-7 in Case No. U-20804.

[22] Ex AG-13, Default MOPR Floor Offer Prices for New Generation Capacity Resources. March 11, 2020. Accessed at https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200311/20200311-item-06c-default-mopr-cone.ashx.

Q For context, how does the value of CONE compare to the capacity price from PJM's most recent capacity auction?

A CONE is much higher than the cleared capacity value (auction price) from PJM's most recent 2022/2023 Baseline Reserve Auction (BRA) because there remains surplus capacity available for participation in the PJM capacity market. This auction produced a capacity price of only $50/MW-Day for years 2022-2023, which is the lowest it has been in the past five auctions. And capacity prices are expected to continue to drop moving forward, based on downward pressure from three main sources: (1) lower demand, as loads continue to drop below what utilties project, due in large part to increasing levels of energy efficiency investment and adoption of behind the meter solar PV;[23] (2) increased supply from the massive quantities of solar and wind (and even gas resources) in the PJM interconnection queue, many of which are coming online in the coming years;[24] (3) relaxation of the MOPR, which more fully allows for capacity credit of new renewables to show up in the PJM capacity auctions. These factors have combined to reduce PJM prices from inordinately high historical levels down to what was seen in the 2022/2023 BRA clearing prices in April of 2021 and will continue to reduce prices in future PJM auctions.

[23] Ex AG-17, PJM, 2023/2024 RPM Base Residual Auction Planning Period Parameters. Accessed at https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2023-2024/2023-2024-planning-period-parameters-for-base-residual-auction-pdf.ashx.

[24] Ex AG-18, PJM, Interconnection Process Reform Task Force Update, May 11, 2021. Accessed at https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20210511/20210511-item-11-interconnection-process-reform-task-force-update.ashx.

Q How do the prices that I&M received in response to its most recent RFP compare to the costs paid under the ICPA?

A The prices that I&M received in its most recent RFP, issued as part of its 2021 integrated resource plan process, are much lower than the costs paid under the ICPA. Specifically, the average bid I&M received for solar PV PPAs was $50/MWh and $44/MWh for a medium and large installations respectively. The average price for a wind PPA was $45/MWh.[25]

Another regional utility, Northern Indiana Public Service Company (NIPSCO), also recently issued an RFP as part of its IRP process and received bids for solar PV, solar PV paired with battery storage, and wind PPAs, all of which were also far below the cost billed under the ICPA.[26]

Q What are your conclusions regarding a benchmark for the power purchased from OVEC under the ICPA?

A The power I&M purchased under the ICPA is extremely high cost by any reasonable measure. I have presented a number of reasonable alternatives in this section, for both current fossil resources contracted under similar PPAs, new fossil resources, and new renewable resource bid prices that demonstrate this point. Yet I&M customers are paying as much as $26 million per year in excess of the cost of these long-term supply comparisons.

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[25] Ex AG-14, Indiana Michigan Power: 2021 Integrated Resource Plan, Public Stakeholder Meeting #3A, July 27, 2021.

[26] Ex AG-15, NIPSCO's 2019 Request for Proposals Results, February 18, 2020.

iv. OVEC operates its two power plants, Clifty Creek and Kyger Creek, uneconomically and incurred $29.5 million in net losses relative to market energy in 2020 alone

Q How often did OVEC operate its plants in 2020?

A OVEC operated the Clifty Creek and Kyger Creek plants at 51 percent and 66 percent capacity factors respectively during 2020 despite both units incurring substantial revenue losses relative to the market. In fact, at least one unit at each plant was online and generating during every hour of 2020.[27] This shows that OVEC is not taking action to limit incurring negative energy margins at its plants, and instead is operating them even when it would cost Sponsoring Companies less to not operate any units.

Q Did OVEC's plants cover their variable operating costs with energy market revenues in 2020?

A No. During 2020, OVEC's variable costs exceeded market locational marginal prices ("LMPs") in 83 percent of the hours in which the units operated. This incurred a total of $29.5 million in variable operating losses across the two plants, $2.3 million of which is allocated to I&M customers.[28] Coal plants such as Clifty Creek and Kyger Creek require high capital costs to stay online, and therefore need large positive energy margins (or sufficient capacity payments) to cover these costs. When a plant loses money on a variable basis, that means it is not covering its fuel and O&M costs, and therefore it is also contributing nothing to

[27] EPA Clean Air Markets, Air Markets Program Data for Clifty Creek and Kyger Creek available at: https://ampd.epa.gov/ampd/; PJM LMPs for OVEC Zone accessed at https://dataminer2.pjm.com/feed/da_hrl_lmps.
[28] *Id.*

offset these significant fixed and capital costs. In 2020, I&M customers would have been better off if the OVEC plants had not operated at all.

Q How did you calculate these variable losses?

A OVEC includes the cost of coal, allowances, and other fuel-related costs in its energy charge,[29] so I used the energy charge as a proxy for the OVEC unit's variable costs. I obtained hourly LMPs for the OVEC units in 2020 from PJM, hourly gross generation from the EPA Clean Air Markets Data set, and monthly net generation from U.S. Energy Information Administration ("EIA") Form 923.[30] I calculated hourly energy market revenue by combining hourly net generation and market LMPs. For each hour in 2020, I compared the monthly billed energy costs to hourly energy market revenue to find the hourly net margin that resulted from operating the unit.

Q How did the OVEC units incur significant losses if they were operating within the PJM market?

A Generators operating within the PJM market generally commit[31] their available units as either economic or must-run. For units committed economically, the market operator, PJM, has the responsibility for unit commitment and dispatch decisions. Those decisions prioritize reliability for the system as a whole, but then select plants to commit and dispatch based on short-term economics to ensure customers are served by the lowest-cost resources available to the system. A plant committed as "economic" will operate only if it is the least-cost option available

[29] I&M Response to Sierra Club Request 2-17, SC 2-17 Attachment 1, Docket No. 20804.
[30] EIA Form 923, accessible at https://www.eia.gov/electricity/data/eia923/.

to the market (i.e., has a lower variable cost than other resources available at the time).

While economic commitment and dispatch tends to be the norm for dispatchable power plants, for units such as OVEC's coal-fired power plants with long start-up and shut-down times, utilities often instead elect to maintain control of unit commitment decisions and utilize a must-run commitment status. For these units, the utility determines independently when to commit a unit. A unit designated as must-run will operate with a power output no less than its minimum operating level.[32] The unit receives market revenue (and incurs variable operational costs) but does not set the market price of energy. If the market price of energy falls below its operational cost, a must-run unit will not turn off and can incur losses that a utility often seeks to recover from ratepayers.

Because units operated by the market follow short-term economic signals, they tend to cycle off when market prices are low and therefore do not generally incur significant operational losses. The OVEC units, on the other hand, stayed online for the majority of 2020 despite incurring significant net revenue losses. This indicates that the units were very likely self-committing as must-run and that OVEC operated the plants without regard to I&M's customers' interests.

[32] Minimum operating level is an output threshold often determined operationally, and below which a generator is either less stable or operates inefficiently. Once the unit commitment decision is made, the level of generation output (above the minimum) is generally left to the market. The operating level is based upon the marginal running cost assumptions provided by the owner in the form of offers or bids to PJM.

Q What drives a power plant operator such as OVEC to uneconomically self-commit its units?

A There are many factors that drive a power plant operator to uneconomically self-commit their units, but four main ones are: (1) a failure to evaluate the economics of daily unit commitment decisions; (2) failure to follow the results of daily unit commitment analysis; (3) incomplete accounting of variable unit costs in unit dispatch bids; and (4) minimum take provisions in fuel contracts that "lock in" costs that would otherwise be variable.

v. <u>I&M has been imprudently managing its ICPA contract with OVEC by failing to take action to influence of the operational decisions made at the plant</u>

Q What is I&M's role in operating the OVEC plants?

A I&M is a Sponsoring Company of OVEC and as such I&M and its AEP affiliates are allowed to appoint one member among them to OVEC's Operating Committee. According to the Amended and Restated Inter-Company Power Agreement (September 10, 2010), the Operating Committee has a role in unit operations:

> *The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03…*[33]

[33] Ex AG-19: ICPA, I&M Response to Sierra Club Request 2-03, SC 2-03 Attachment 1, Case No. 20804.

Q What are standard industry practices undertaken by regulated utilities to ensure plants that they co-own are prudently operated?

A Prudent utility management practices dictate a utility would do the following in managing the operation of a plant that it co-owns to manage the costs passed on to its ratepayers:

1. Exercise oversight and have knowledge of the operational decisions that impact the costs passed on to its ratepayers.
2. Evaluate and undertake measures to reduce operational costs at the units that are operating at a loss relative to alternatives or the market.

Q What steps has I&M taken to limit costs incurred for customers under the ICPA?

A I find that I&M has taken no steps to limit the uneconomic commitment practices that are driving the high variable costs at OVEC's or to otherwise limit customer costs incurred under the ICPA units.

When asked to identify actions taken by itself or other co-owners to limit customer costs under the ICPA, the Company responded that "All actions taken by the ICPA sponsoring companies to affect any operations of OVEC must be made through the Operating Committee and require a majority vote by that committee. The Company, through its AEPSC Commercial Operations representative, participated in the Operating Committee meetings during 2020."[34] When asked in follow-up about what specific actions the Operating Committee

[34] Ex AG-20, I&M Response to Attorney General Request 1-09.

may have taken to limit costs under the ICPA, the Company refused to provide documentation of any actions or discussion of any actions taken to limit costs.[35]

Q What do you conclude regarding I&M's management of the ICPA with OVEC?

A Although I&M has the authority under the ICPA to at least influence some of the operational decisions at OVEC that caused excess costs for I&M customers in 2020, the Company either declined to invoke that authority or just refuses to explain what may have occurred. Instead, I&M has passed these costs on to its customers without any documented effort to reduce costs through exercise of its ownership stake in OVEC.

Q What are your recommendations to the Commission regarding the OVEC units?

A The Commission should disallow in this proceeding $3.7 million, which is Michigan's jurisdictional share of the total $26.5 million in excess compensation that I&M paid for OVEC services under the ICPA (relative to the market value of the services). This represents the difference between what I&M charged customers for OVEC power, and the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in 2020.

[35] Ex AG-21, I&M Response to Attorney General Request 3-34.

4. <u>I&M ALSO PAID EXCESS AND ABOVE-MARKET COSTS TO AEG FOR POWER FROM ROCKPORT IN 2020</u>

i. Overview of Rockport Units 1 and 2

Q Provide an overview of the Rockport Generating Station.

A The Rockport Generating Station is a two-unit coal-fired power station located in Spencer County, Indiana. The plant is operated by I&M. Unit 1 has a nameplate capacity of 1,320 MW and Unit 2 is 1,300 MW. Unit 1 is 50 percent owned by I&M and 50 percent owned by AEG. Unit 2 is owned by non-affiliated parties and is leased back to I&M and AEG at a 50 percent share each. AEG sells 70 percent of its share of each Rockport unit back to I&M and 30 percent to Kentucky Power's ("KPCo") under a unit power sales agreement.[36]

Q How often was Rockport used in 2020?

A The Rockport units operated at only a 17.5 percent capacity factor in 2020.[37]

Q What portion of Rockport's costs is I&M responsible for and how are those costs passed on to its ratepayers?

A I&M is responsible for the costs associated with the 50 percent share of Rockport 1 that it owns and the 50 percent share of Rockport 2 that it leases. The associated fuel costs are planned for in PSCR dockets, passed on directly to customers as fuel costs through fuel clauses, and reconciled in the current docket. The

[36] Direct Testimony of Hazel Baker, in Case No. U-20529, 2 TR 76.
[37] EIA Form 923, accessible at https://www.eia.gov/electricity/data/eia923/.

remaining unit costs are passed on to ratepayer through rate cases and other dockets.

I&M also is responsible for the costs associated with the 70 percent share of AEG's portion of Rockport it purchases through the UPA. Because this power is procured through a PPA, instead of from a unit operated by I&M, the entire cost of this share is passed on directly to customers through fuel clauses (not just the fuel costs).

In total, I&M is responsible for 85 percent of the costs associated with Rockport Units 1 and 2.

ii. ***I&M paid excessive and above-market costs for power from Rockport to its affiliate AEG in 2020***

Q What did I&M's purchases of Rockport power from AEG cost in 2020?

A I&M purchased 1,413,574 MWh of Rockport power from AEG in 2020 for a total cost of $172,793,698. That comes out to $122.24/MWh.[38]

Q Under what agreement does I&M make these purchases?

A I&M purchases power from Rockport Units 1 and 2 under the UPA with AEG dated March 31, 1982 and an amendment dated May 8, 1989.[39]

Q Are I&M and AEG affiliates?

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[38] Exhibit IM-4 (JEW-1), (p.3).

[39] Ex AG-22, UPA provided as I&M Response to AG Request 1-11 Attachment.

A Yes. Both AEG and I&M are subsidiaries of AEP. I am advised by counsel that the MPSC Code of Conduct's affiliate price cap would apply to the AEG purchases just as it does to the OVEC purchases. Another affiliate relationship can be found in the fact that I&M operates the plant that produces the power that it buys from AEG.

Q **What does the UPA require I&M to pay AEG?**

A I&M is required to pay AEG an energy charge and a demand charge to receive the energy and capacity allotted to I&M from AEG's owned and leased shares of Rockport.[40] The demand charge includes a return on common equity ("ROE") to AEG.

Q **What is the ROE that I&M pays to AEG?**

A The ROE is set at 12.16 percent.[41]

Q **Did the Commission approve the UPA or the amendment?**

A Only partially. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Unit 2 capacity from AEG in a 1991 order.[42] But as part of that order, a settlement agreement was approved that allowed any party to challenge capacity charges associated with Rockport 2 "if circumstances change such that Michigan ratepayers are no longer fairly compensated for the cost of the generating capacity which I&M makes available to the AEP System." [43]

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[40] Section 1.3 of the UPA, Ex AG-22.
[41] Ex AG-23, Excerpt of FERC application concerning the UPA, ER19-717-000.
[42] Ex AG-24, I&M Response to AG Request 2-29.
[43] Ex AG-25, Settlement Agreement in Case No. U-9656, Paragraph 10.

I&M has not identified any Commission Order approving charges related to the AEG share of Rockport Unit 1. In addition, I&M has not identified any Commission Order adjudicating the UPA's compliance with the MPSC Code of Conduct.

Q Has the Commission issued any direction to I&M in recent years regarding the purchases from AEG under the UPA?

A Yes. In 2019, the Commission issued an order in Case U-18404,[44] in response to a recommendation by Attorney General regarding the ROE awarded to AEG. This order reiterated that I&M has an obligation to examine existing contracts as market conditions change, and make good-faith attempts to negotiate and amend these contracts. Further, the Commission stated that I&M was expected to "demonstrate to this Commission, in the PSCR reconciliation proceeding and future plan cases, that its wholesale purchases from affiliates are just and reasonable under current market conditions… and that the utility is taking appropriate actions to minimize costs to ratepayers pursuant to Act 304."[45]

Q Has I&M taken any action in response to the Commission Order in U-18404 with respect to the AEG contract?

A It appears not. When asked in discovery to identify all actions I&M has taken since the Order in U-18404 to seek any changes to the UPA, I&M refers only to FERC Docket No. ER19-717-000. That concluded in February 2019, before the Order in U-18404 was issued and retained the 12.16 percent ROE.

[44] Commission Order dated June 7, 2019 in Case U-18404.
[45] *Id*., pages 7-8.

Q How does the cost of the Rockport power from the AEG contract compare to market price?

A I&M received an average of \$21.23/MWh in energy and ancillary revenues from the market for the Rockport power it purchased from AEG in 2020. I estimate the capacity value of the 917 MW[46] portion of Rockport owned by AEG and purchased by I&M through a PPA based on the PJM market capacity value in 2020 as \$19.56/MWh.[47] This adds up to a total market value of \$40.79/MWh. But AEG billed I&M \$122.24/MWh. This means that I&M customers are paying an estimated \$81.45/MWh premium[48] for Rockport's energy and capacity services over the equivalent value of the energy and capacity in the PJM market. This works out to a total \$115.1 million premium for Rockport services allocated to I&M based on the UPA. Approximately \$16.1 million of this will be passed onto Michigan customers in this reconciliation docket.

Q How does the cost of the Rockport power from the AEG contract compare to the other long-term supply benchmarks that you discussed earlier in your testimony?

A It exceeds all of them. In fact, it is more than twice as much as any of them.

Q What are your recommendations to the Commission regarding I&M's payment to AEG under the UPA?

A The Commission should disallow in this proceeding \$16.1 million, which is Michigan's jurisdictional share of the total \$115.1 million in excess compensation

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46 Direct Testimony of Hazel A. Baker in Case No. U-20529, 2 TR 75.
47 Ex AG-26 pages 302-303.
48 Exhibit IM-4 (JEW-1), (p.3); Ex AG-4.

that I&M paid AEG for power from Rockport services under the UPA (relative to the market value of the services). This represents the difference between what I&M charged customers for Rockport power purchased from AEG power, and the equivalent price that I&M would pay to procure the energy, capacity, and ancillary services from the PJM market in 2020.

5. I&M IMPRUDENTLY SELF-COMMITTED ROCKPORT IN 2020, AND INCURRED AVOIDABLE LOSSES AS A RESULT OF THOSE DECISIONS

i. I&M regularly self-committed Rockport in 2020

Q What does the phrase "uneconomic self-commitment" mean?

A The term uneconomic self-commitment refers to a utility's decision to commit a unit into the PJM market with a "must-run" status when it knows that market energy and ancillary service revenues are not sufficient to cover fuel and variable operating costs.

Day-ahead market prices are known with certainty for the next day and can be projected with a sufficient level of accuracy for the purposes of unit commitment. Fuel and variable O&M costs are also known with relative certainty a few days out, and start-up costs are known and should not fluctuate significantly over the course of the week. This means that at the time the utility makes a decision to self-commit a unit in the day-ahead market (i.e., to either bring the unit online, keep it online, take it offline, or keep it offline) it has the information needed to make a prudent decision. That decision should maximize projected net revenues/minimize projected net losses to ratepayers over a several-day period.

Q Should a utility be considered to have made an imprudent decision any time it doesn't maximize actual revenues to ratepayers?

A Not necessarily. Utilities are expected to use accurate cost and pricing information and to make prudent decisions based on that information, but they are not expected to always be right. If market prices deviate significantly from what the utility reasonably projected, the company's self-commitment decisions may not actually maximize net revenues. But in order to be prudent, the utility's decision to self-commit its unit must have been projected to maximize net revenues at the time the company made the must-run commitment decision.

Q What tools does I&M have to inform its unit commitment decisions?

A I&M has developed a price-based forward-looking analysis process. I&M conducts this analysis every day to determine whether to commit its units the next day. The Company records all revenue projections and commitment decisions for the following day on a sheet the Company calls its "6-Day forecast" sheets.[49]

In these assessments, the Company reviews forecasted energy market prices and projected variable operational costs for the next six days to project net operational revenues (or losses) for each unit for each individual day and over the entire 6-day period.[50] If a unit is projected to be profitable, then ratepayers expect to see savings from operating the unit relative to the acquisition of market-supplied power. If the unit is projected to lose money, then ratepayers expect to see savings by the acquisition of market-supplied power.

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[49] I&M Response to Attorney General Request 1.05(c), CONFIDENTIAL Attachments (365 total).

[50] *Id.*

Q What exactly does the analysis from the 6-day forecast sheets represent?

A The data provided in the 6-day forecast sheets represents the information that the Company has on market prices and unit costs at the time it is making its unit commitment decisions. While it is true that market prices and other market inputs are constantly changing, there is a knowable set of information on unit costs and market prices at the time commitment decisions are made and submitted to PJM. Regardless of whether prices may continue to change, the Company can and should save the full set of information it has at the time of its decisions to allow the Commission to assess the prudency of its decisions.[51]

Q How should I&M be using the results of its price-based analysis to inform unit commitment decisions?

A I&M should either (a) commit its units as economic and let the market decide when to operate the units, or (b) make unit commitment decisions based on the results of its price-based analysis and document any deviations from its quantitative analysis. Specifically, I&M should elect to self-commit its units as must-run on a forward-looking basis only if it expects to make positive energy market margins over a reasonable near-term time period (incorporating consideration of start-up and shut-down costs), and the Company should commit it as "economic" with the expectation it will not run if it is projected to operate at a loss.

[51] *Id.*

Q Does I&M follow its price-based analysis to make its unit commitment decision at Rockport Units 1 and 2?

A No. I&M does not always rely on the results of its 6-day forecasts to inform its unit commitment decision at Rockport Units 1 and 2. Instead, the Company regularly self-commits the units regardless of what its price-based analysis projects about unit performance.

Q How did I&M commit its Rockport Units 1 and 2 during the reconciliation period of January 1, 2020 through December 31, 2020?

A Based on the Company's unit commitment data, I find that during the reconciliation period, the Company self-committed (i.e., entered the unit into the PJM market with a must-run status) Rockport Units 1 and 2 the majority of the time that the units were available.[52]

Table 2: CONFIDENTIAL Unit commitment decisions for Rockport Units 1 and 2 (non-outage hours)

	Jan 1 – Dec 31, 2020	
	Must-Run	**Economic**
Rockport 1	[[[redacted]	[redacted]
Rockport 2	[redacted]	[redacted]

Sources: I&M Response to Attorney General Request 1-5, AG 1-5 CONF Attachment 1.

Q Why is it concerning for ratepayers that I&M is using a must-run commitment status at its coal-fired generating units so frequently?

A I&M should be committing its units economically into the market. It is only reasonable for I&M to take control of its unit commitment decisions from the

[52] I&M Response to Attorney General Request 1-5, AG 1-5 CONF Attachment 1.

market-based PJM algorithm if the utility demonstrates that its internal price-based analysis process produces greater net revenues and a more-economic outcome for ratepayers than relying solely on the PJM market. But I&M has not demonstrated this to be the case. This means the Company is either ignoring the results of its own analysis or bidding the units into the market at a cost below the units' true marginal cost.

This is concerning because if and when I&M commits a unit in PJM uneconomically (that is with variable costs above the market LMP) I&M is only paid by PJM based on the market LMP.[53] But I&M still incurs the full cost to run that plant. This means that the fuel costs not economically incurred are passed on to I&M ratepayers in their monthly bills through the PSCR clause.

Q What did you find regarding the Company's use of its unit commitment analysis?

A I found that the Company frequently ignores the results of its own analysis when determining its unit commitment decision. I&M's 6-day forecast sheets show that the Company made imprudent unit commitment decisions that resulted in net losses during nearly every month of the reconciliation period.

I&M self-committed Rockport Units 1 and 2 despite projecting net operational losses from committing the units as must-run in [[[redacted]]] operational months at Rockport 1 and for [[[redacted]] operational months at Rockport 2 in 2020.[54] This means that during just the subset of hours where I&M committed the units

[53] The market revenue I&M receives includes energy and ancillary market revenue from both the day-ahead and real-time markets.
[54] I&M Response to Attorney General Request 1.05(c), CONFIDENTIAL Attachments (365 total).

with a must-run status, the Company itself had projected net operational losses from operating each unit. Net operational revenues would have been higher if the units had been economically committed during each of these periods. This is because, if given the choice, the market would have chosen not to commit the Rockport units during many hours when they were otherwise locked in by I&M with a must-run status.

Q What is the magnitude of avoidable losses incurred as a direct result of uneconomic unit commitment decisions?

A Based on the data provided by I&M in its 6-day forecast reports as well as its actual net revenue data, I find that I&M incurred an avoidable [redacted] in net losses. These losses were incurred over six distinct periods (shown in Table 3 below) where the Company self-committed a Rockport unit with a must-run status despite its own 6-day forecasts projecting that net revenue losses would result from the decision to self-commit the unit.

Table 3: CONFIDENTIAL Avoidable losses from events where the Company committed the Rockport units with a must-run status

Unit	Begin must-run event	End must-run event	Length of must-run Event	Projected losses during month of event from 6-day forecasts	Actual losses
Rockport 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport 1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport 2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rockport Total				[redacted]	[redacted]
I&M Share of Rockport				[redacted]	
I&M Ownership Share				[redacted]	[redacted]
Fuel Portion of Costs				[redacted]	[redacted]
Michigan Share of Fuel Costs				[redacted]	[redacted]

Source: I&M Response to Attorney General Request 1.05(c), CONFIDENTIAL Attachments (365 total); I&M Response to Attorney General Request 3-47, AG_3-43_Attachment_1.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_3_-_Parts_D_E_and_R.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_4_-_Parts_G_and_I.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_5_-_Part_J.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_6_-Parts_L_N_and_O.xlsx.

ii. I&M has been operating, and continues to operate, the two Rockport units uneconomically, and incurred [redacted] in net revenue losses in 2020

Q Please summarize the actual performance of Rockport's units during 2020 based on the Company's actual operational data.

A I reviewed data reported by I&M on the marginal variable costs that the Company incurred (fuel and variable O&M) and the actual energy market revenues that

I&M earned from operation of the Rockport plant in 2020. As shown in Table 4, I find that in 2020 the variable costs at Rockport Units 1 and 2 exceeded market revenue during [[[redacted]]] percent respectively of the hours that each unit was online (Units 1 and 2 were offline for [redacted] percent respectively of the hours in 2020). This resulted in total net losses of [redacted] at the Rockport plant in 2020,[55] [redacted] of which is allocated to I&M customers.[56]

[55] I&M Response to Attorney General Request 3-47, AG_3-43_Attachment_1.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_3_-_Parts_D_E_and_R.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_4_-_Parts_G_and_I.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_5_-_Part_J.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_6_-Parts_L_N_and_O.xlsx..

[56] *Id.*

Table 4: CONFIDENTIAL Rockport Units 1 and 2 percent of hours online, percent of hours with net losses, and total net losses incurred in 2020

	Percent of hours offline		Percent of online hours with net losses		Net Losses ($Million)	
Month	**Unit 1**	**Unit 2**	**Unit 1**	**Unit 2**	**Unit 1**	**Unit 2**
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
% of hours	[redacted]	[redacted]	[redacted]	[redacted]		
Total	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Source: I&M Response to Attorney General Request 3-47, AG_3-43_Attachment_1.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_3_-_Parts_D_E_and_R.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_4_-_Parts_G_and_I.xlsx; I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_5_-_Part_J.xlsx; I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_6_-Parts_L_N_and_O.xlsx.

Q How were the values in Table 4 calculated?

A I calculated the values in Table 4 based on the Company's own hourly cost and operational revenue data. The Company provided hourly marginal variable production cost values (which includes fuel and variable O&M)[57] and hourly

[57] I&M Response to Attorney General Request 3-47, CONFIDENTIAL_Attachment_4_-_Parts_G_and_I.xlsx.

generation,[58] which I multiplied together to get total variable production cost. I based my calculations on marginal "replacement" fuel costs as opposed to accounting as-burned cost of fuel based on prior rulings by the MPSC that the replacement cost of coal, and not the accounting cost of coal as burned, should be used to evaluate the Company's decision to offer its coal-fired plants.[59] I then calculated net operational revenues by comparing the total variable production costs to the operational revenues (energy and ancillary service revenues)[60] provided by the Company. I removed losses incurred during planned and unplanned outages (as identified by the Company), and then I summed the net hourly revenues for each hour in a month to find the monthly totals displayed in the table.

Q What are your recommendations to the Commission regarding Rockport?

A The Commission should disallow in this proceeding [redacted], which represents I&M's ownership share (50 percent) of Michigan's jurisdictional share of the [redacted] in fuel costs out of the [redacted] in unnecessary variable costs incurred at Rockport as a result of I&M's uneconomic unit commitment practices. Specifically, the recommended disallowance represents the excess fuel costs that I&M incurred by operating a Rockport unit during the specific events discussed above relative to what it paid for energy in the market. These losses were avoidable if I&M had followed the results of its own price-based process and therefore should not be passed on to ratepayers.

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[58] I&M Response to Attorney General Request 3-47, AG_3-47_CONFIDENTIAL_Attachment_5_-_Part_J.xlsx.

[59] Order dated February 5, 2018 in MPSC Case No. U-17678-R (pp. 14-20).

[60] I&M Response to Attorney General Request 3-47, AG_3-43_Attachment_1.xlsx.

Q Why is this requested disallowance so much smaller than the disallowance requested for the power I&M purchases from AEG?

A In this reconciliation docket, only fuel and purchased power costs are reconciled. All other variable costs, maintenance costs, and capital costs directly incurred by the Company to operate its own units are addressed in separate proceedings.

The disallowance requested directly above covers only the fuel portion of the variable costs incurred at the 50 percent share of Rockport Units 1 and 2 owned by I&M. Further, the disallowance is not for all net losses, but just the portion of losses that were incurred based on documented imprudent commitment decision by I&M.

In contrast, the disallowance requested in Section 4 covers the entire cost to operate the 35 percent share of Rockport that I&M purchases from AEG. This includes all fuel costs, O&M costs, and capital costs. The entire cost is passed on to I&M customers through a PPA. Here we ask for a disallowance based on how the entire power purchase cost compares to the market value of energy and capacity.

Q Does this conclude your testimony?

A Yes.

Devi Glick, Principal Associate

Synapse Energy Economics I 485 Massachusetts Avenue, Suite 3 I Cambridge, MA 02139 I 617-453-7050
dglick@synapse-energy.com

PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Principal Associate*, June 2021- Present; *Senior Associate*, April 2019 – June 2021; *Associate*, January 2018 – March 2019.

Conducts research and provides expert witness and consulting services on energy sector issues. Examples include:

- Modeling for resource planning using PLEXOS and Encompass utility planning software to evaluate the reasonableness of utility IRP modeling.
- Modeling for resource planning to explore alternative, lower-cost and lower-emission resource portfolio options.
- Providing expert testimony in rate cases on the prudence of continued investment in, and operation of, coal plants based on the economics of plant operations relative to market prices and alternative resource costs.
- Providing expert testimony and analysis on the reasonableness of utility coal plant commitment and dispatch practice in fuel and power cost adjustment dockets.
- Serving as an expert witness on avoided cost of distributed solar PV and submitting direct and surrebuttal testimony regarding the appropriate calculation of benefit categories associated with the value of solar calculations.
- Reviewing and assessing the reasonableness of methodologies and assumptions relied on in utility IRPs and other long-term planning documents for expert report, public comments, and expert testimony.
- Evaluating utility long-term resource plans and developing alternative clean energy portfolios for expert reports.
- Co-authoring public comments on the adequacy of utility coal ash disposal plans, and federal coal ash disposal rules and amendments.
- Analyzing system-level cost impacts of energy efficiency at the state and national level.

Rocky Mountain Institute, Basalt, CO. August 2012 – September 2017
Senior Associate

- Led technical analysis, modeling, training and capacity building work for utilities and governments in Sub-Saharan Africa around integrated resource planning for the central electricity grid energy. Identified over one billion dollars in savings based on improved resource-planning processes.
- Represented RMI as a content expert and presented materials on electricity pricing and rate design at conferences and events.

- Led a project to research and evaluate utility resource planning and spending processes, focusing specifically on integrated resource planning, to highlight systematic overspending on conventional resources and underinvestment and underutilization of distributed energy resources as a least-cost alternative.

Associate

- Led modeling analysis in collaboration with NextGen Climate America which identified a CO2 loophole in the Clean Power Plan of 250 million tons, or 41 percent of EPA projected abatement. Analysis was submitted as an official federal comment which led to a modification to address the loophole in the final rule.
- Led financial and economic modeling in collaboration with a major U.S. utility to quantify the impact that solar PV would have on their sales and helped identify alternative business models which would allow them to recapture a significant portion of this at-risk value.
- Supported the planning, content development, facilitation, and execution of numerous events and workshops with participants from across the electricity sector for RMI's Electricity Innovation Lab (eLab) initiative.
- Co-authored two studies reviewing valuation methodologies for solar PV and laying out new principles and recommendations around pricing and rate design for a distributed energy future in the United States. These studies have been highly cited by the industry and submitted as evidence in numerous Public Utility Commission rate cases.

The University of Michigan, Ann Arbor, MI. *Graduate Student Instructor*, September 2011 – July 2012

The Virginia Sea Grant at the Virginia Institute of Marine Science, Gloucester Point, VA. *Policy Intern*, Summer 2011

Managed a communication network analysis study of coastal resource management stakeholders on the Eastern Shore of the Delmarva Peninsula.

The Commission for Environmental Cooperation (NAFTA), Montreal, QC. *Short Term Educational Program/Intern*, Summer 2010

Researched energy and climate issues relevant to the NAFTA parties to assist the executive director in conducting a GAP analysis of emission monitoring, reporting, and verification systems in North America.

Congressman Tom Allen, Portland, ME. *Technology Systems and Outreach Coordinator*, August 2007 – December 2008

Directed Congressman Allen's technology operation, responded to constituent requests, and represented the Congressman at events throughout southern Maine.

EDUCATION

The University of Michigan, Ann Arbor, MI
Master of Public Policy, Gerald R. Ford School of Public Policy, 2012
Master of Science, School of Natural Resources and the Environment, 2012
Masters Project: *Climate Change Adaptation Planning in U.S. Cities*

Middlebury College, Middlebury, VT
Bachelor of Arts, 2007
Environmental Studies, Policy Focus; Minor in Spanish
Thesis: *Environmental Security in a Changing National Security Environment: Reconciling Divergent Policy Interests, Cold War to Present*

PUBLICATIONS

Glick, D. *Synapse Comments and Surreply Comments to the Minnesota Public Utility Commission in response to Otter Tail Power's 2021 Compliance Filing* Docket E-999/CI-19-704. Synapse Energy Economics for the Sierra Club.

Eash-Gates, P., D. Glick, S. Kwok. R. Wilson. 2020. *Orlando's Renewable Energy Future: The Path to 100 Percent Renewable Energy by 2020.* Synapse Energy Economics for the First 50 Coalition.

Eash-Gates, P., B. Fagan, D. Glick. 2020. *Alternatives to the Surry-Skiffes Creek 500 kV Transmission Line.* Synapse Energy Economics for the National Parks Conservation Association.

Biewald, B., D. Glick, J. Hall, C. Odom, C. Roberto, R. Wilson. 2020. *Investing in Failure: How Large Power Companies are Undermining their Decarbonization Targets.* Synapse Energy Economics for Climate Majority Project.

Glick, D., D. Bhandari, C. Roberto, T. Woolf. 2020. *Review of benefit-cost analysis for the EPA's proposed revisions to the 2015 Steam Electric Effluent Limitations Guidelines.* Synapse Energy Economics for Earthjustice and Environmental Integrity Project.

Camp, E., B. Fagan, J. Frost, N. Garner, D. Glick, A. Hopkins, A. Napoleon, K. Takahashi, D. White, M. Whited, R. Wilson. 2019. *Phase 2 Report on Muskrat Falls Project Rate Mitigation, Revision 1 – September 25, 2019.* Synapse Energy Economics for the Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Camp, E., A. Hopkins, D. Bhandari, N. Garner, A. Allison, N. Peluso, B. Havumaki, D. Glick. 2019. *The Future of Energy Storage in Colorado: Opportunities, Barriers, Analysis, and Policy Recommendations.* Synapse Energy Office for the Colorado Energy Office.

Glick, D., B. Fagan, J. Frost, D. White. 2019. *Big Bend Analysis: Cleaner, Lower-Cost Alternatives to TECO's Billion-Dollar Gas Project*. Synapse Energy Economics for Sierra Club.

Glick, D., F. Ackerman, J. Frost. 2019. *Assessment of Duke Energy's Coal Ash Basin Closure Options Analysis in North Carolina.* Synapse Energy Economics for the Southern Environmental Law Center.

Glick, D., N. Peluso, R. Fagan. 2019. *San Juan Replacement Study: An alternative clean energy resource portfolio to meet Public Service Company of New Mexico's energy, capacity, and flexibility needs after the retirement of the San Juan Generating Station*. Synapse Energy Economics for Sierra Club.

Suphachalasai, S., M. Touati, F. Ackerman, P. Knight, D. Glick, A. Horowitz, J.A. Rogers, T. Amegroud. 2018. *Morocco – Energy Policy MRV: Emission Reductions from Energy Subsidies Reform and Renewable Energy Policy.* Prepared for the World Bank Group.

Camp, E., B. Fagan, J. Frost, D. Glick, A. Hopkins, A. Napoleon, N. Peluso, K. Takahashi, D. White, R. Wilson, T. Woolf. 2018. *Phase 1 Findings on Muskrat Falls Project Rate Mitigation.* Synapse Energy Economics for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador.

Allison, A., R. Wilson, D. Glick, J. Frost. 2018. *Comments on South Africa 2018 Integrated Resource Plan.* Synapse Energy Economics for Centre for Environmental Rights.

Hopkins, A. S., K. Takahashi, D. Glick, M. Whited. 2018. *Decarbonization of Heating Energy Use in California Buildings: Technology, Markets, Impacts, and Policy Solutions*. Synapse Energy Economics for the Natural Resources Defense Council.

Knight, P., E. Camp, D. Glick, M. Chang. 2018. *Analysis of the Avoided Costs of Compliance of the Massachusetts Global Warming Solutions Act*. Supplement to 2018 AESC Study. Synapse Energy Economics for Massachusetts Department of Energy Resources and Massachusetts Department of Environmental Protection.

Fagan, B., R. Wilson, S. Fields, D. Glick, D. White. 2018. *Nova Scotia Power Inc. Thermal Generation Utilization and Optimization: Economic Analysis of Retention of Fossil-Fueled Thermal Fleet to and Beyond 2030 – M08059*. Prepared for Board Counsel to the Nova Scotia Utility Review Board.

Ackerman, F., D. Glick, T. Vitolo. 2018. *Report on CCR proposed rule*. Prepared for Earthjustice.

Lashof, D. A., D. Weiskopf, D. Glick. 2014. *Potential Emission Leakage Under the Clean Power Plan and a Proposed Solution: A Comment to the US EP*A. NextGen Climate America.

Smith, O., M. Lehrman, D. Glick. 2014. *Rate Design for the Distribution Edge*. Rocky Mountain Institute.

Hansen, L., V. Lacy, D. Glick. 2013. *A Review of Solar PV Benefit & Cost Studies*. Rocky Mountain Institute.

TESTIMONY

Public Utilities Commission of Nevada (Docket No. 21-06001): Direct Testimony of Devi Glick in the joint application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their 2022-2041 Triennial Intergrade Resource Plan and 2022-2024 Energy Supply Plan. On behalf of Sierra Club and Natural Resource Defense Council. August 16, 2021.

North Carolina Utilities Commission (Docket No. E-7, Sub 1250): Direct Testimony of Devi Glick in the Mater of Application Duke Energy Carolinas, LLC Pursuant to §N.C.G.S 62-133.2 and Commission Rule R8-5 Relating to Fuel and Fuel-Related Charge Adjustments for Electric Utilities. On behalf of Sierra Club. May 17, 2021.

Public Utility Commission of Texas (PUC Docket No. 51415): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to change rates. On behalf of Sierra Club. March 31, 2021.

Michigan Public Service Commission (Docket No. U-20804): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for approval of a Power Supply Cost Recovery Plan and factors (2021). On behalf of Sierra Club. March 12, 2021.

Public Utility Commission of Texas (PUC Docket No. 50997): Direct Testimony of Devi Glick in the application of Southwestern Electric Power Company for authority to reconcile fuel costs for the period May 1, 2017- December 31, 2019. On behalf of Sierra Club. January 7, 2021.

Michigan Public Service Commission (Docket No. U-20224): Direct Testimony of Devi Glick in the application of Indiana Michigan Power Company for Reconciliation of its Power Supply Cost Recovery Plan (Case No. U-20223) for the 12-month period ending December 31, 2019. On behalf of Sierra Club. October 23, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Surrebuttal Testimony of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 29, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Surrebuttal Testimony of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 21, 2020.

Public Service Commission of Wisconsin (Docket No. 3270-UR-123): Direct Testimony and Exhibits of Devi Glick in the application of Madison Gas and Electric Company for authority to change electric and natural gas rates. On behalf of Sierra Club. September 18, 2020.

Public Service Commission of Wisconsin (Docket No. 6680-UR-122): Direct Testimony and Exhibits of Devi Glick in the application of Wisconsin Power and Light Company for approval to extend electric and natural gas rates into 2021 and for approval of its 2021 fuel cost plan. On behalf of Sierra Club. September 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC125): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. September 4, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123 S1): Direct Testimony and Exhibits of Devi Glick in the Subdocket for review of Duke Energy Indian, LLC's Generation Unit Commitment Decisions. On behalf of Sierra Club. July 31, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC124): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. June 4, 2020.

Arizona Corporation Commission (Docket No. E-01933A-19-0028): Rely to Late-filed ACC Staff Testimony of Devi Glick in the application of Tucson Electric Power Company for the establishment of just and reasonable rates. On behalf of Sierra Club. May 8, 2020.

Indiana Utility Regulatory Commission (Cause No. 38707-FAC123): Direct Testimony and Exhibits of Devi Glick in the application of Duke Energy Indiana, LLC for approval of a change in its fuel cost adjustment for electric service. On behalf of Sierra Club. March 6, 2020.

Texas Public Utility Commission (PUC Docket No. 49831): Direct Testimony of Devi Glick in the application of Southwestern Public Service Company for authority to change rates. On behalf of Sierra Club. February 10, 2020.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Testimony of Devi Glick in Support of Uncontested Comprehensive Stipulation. On behalf of Sierra Club. January 21, 2020.

Nova Scotia Utility and Review Board (Matter M09420): Expert Evidence of Fagan, B, D. Glick reviewing Nova Scotia Power's Application for Extra Large Industrial Active Demand Control Tariff for Port Hawkesbury Paper. Prepared for Nova Scotia Utility and Review Board Counsel. December 3, 2019.

New Mexico Public Regulation Commission (Case No. 19-00170-UT): Direct Testimony of Devi Glick regarding Southwestern Public Service Company's application for revision of its retail rates and authorization and approval to shorten the service life and abandon its Tolk generation station units. On behalf of Sierra Club. November 22, 2019.

North Carolina Utilities Commission (Docket No. E-100, Sub 158): Responsive testimony of Devi Glick regarding battery storage and PURPA avoided cost rates. On behalf of Southern Alliance for Clean Energy. July 3, 2019.

State Corporation Commission of Virginia (Case No. PUR-2018-00195): Direct testimony of Devi Glick regarding the economic performance of four of Virginia Electric and Power Company's coal-fired units and the Company's petition to recover costs incurred to company with state and federal environmental regulations. On behalf of Sierra Club. April 23, 2019.

Connecticut Siting Council (Docket No. 470B): Joint testimony of Robert Fagan and Devi Glick regarding NTE Connecticut's application for a Certificate of Environmental Compatibility and Public Need for the Killingly generating facility. On behalf of Not Another Power Plant and Sierra Club. April 11, 2019.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Surrebuttal testimony of Devi Glick regarding annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 31, 2018.

Public Service Commission of South Carolina (Docket No. 2018-3-E): Direct testimony of Devi Glick regarding the annual review of base rates of fuel costs for Duke Energy Carolinas. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. August 17, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Surrebuttal testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. June 4, 2018.

Public Service Commission of South Carolina (Docket No. 2018-1-E): Direct testimony of Devi Glick regarding Duke Energy Progress' net energy metering methodology for valuing distributed energy resources system within South Carolina. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. May 22, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Direct testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 12, 2018.

Public Service Commission of South Carolina (Docket No. 2018-2-E): Surrebuttal testimony of Devi Glick on avoided cost calculations and the costs and benefits of solar net energy metering for South Carolina Electric and Gas Company. On behalf of South Carolina Coastal Conservation League and Southern Alliance for Clean Energy. April 4, 2018.

Resume updated August 2021

ANNUAL REPORT — 2019

OHIO VALLEY ELECTRIC CORPORATION

and subsidiary

INDIANA-KENTUCKY ELECTRIC CORPORATION

Ohio Valley Electric Corporation

GENERAL OFFICES, 3932 U.S. Route 23, Piketon, Ohio 45661

Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies, were organized on October 1, 1952. The Companies were formed by investor-owned utilities furnishing electric service in the Ohio River Valley area and their parent holding companies for the purpose of providing the large electric power requirements projected for the uranium enrichment facilities then under construction by the Atomic Energy Commission (AEC) near Portsmouth, Ohio.

OVEC, AEC and OVEC's owners or their utility-company affiliates (called Sponsoring Companies) entered into power agreements to ensure the availability of the AEC's substantial power requirements. On October 15, 1952, OVEC and AEC executed a 25-year agreement, which was later extended through December 31, 2005 under a Department of Energy (DOE) Power Agreement. On September 29, 2000, the DOE gave OVEC notice of cancellation of the DOE Power Agreement. On April 30, 2003, the DOE Power Agreement terminated in accordance with the notice of cancellation.

OVEC and the Sponsoring Companies signed an Inter-Company Power Agreement (ICPA) on July 10, 1953, to support the DOE Power Agreement and provide for excess energy sales to the Sponsoring Companies of power not utilized by the DOE or its predecessors. Since the termination of the DOE Power Agreement on April 30, 2003, OVEC's entire generating capacity has been available to the Sponsoring Companies under the terms of the ICPA. The Sponsoring Companies and OVEC entered into an Amended and Restated ICPA, effective as of August 11, 2011, which extends its term to June 30, 2040.

OVEC's Kyger Creek Plant at Cheshire, Ohio, and IKEC's Clifty Creek Plant at Madison, Indiana, have nameplate generating capacities of 1,086,300 and 1,303,560 kilowatts, respectively. These two generating stations, both of which began operation in 1955, are connected by a network of 705 circuit miles of 345,000-volt transmission lines. These lines also interconnect with the major power transmission networks of several of the utilities serving the area.

The current Shareholders and their respective percentages of equity in OVEC are:

Allegheny Energy, Inc.[1]	3.50
American Electric Power Company, Inc.*	39.17
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Ohio Edison Company[1]	0.85
Ohio Power Company**[6]	4.30
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
The Toledo Edison Company[1]	4.00
	100.00

The Sponsoring Companies are each either a shareholder in the Company or an affiliate of a shareholder in the Company, with the exception of Energy Harbor Corp. The Sponsoring Companies currently share the OVEC power participation benefits and requirements in the following percentages:

Allegheny Energy Supply Company LLC[1]	3.01
Appalachian Power Company[6]	15.69
Buckeye Power Generating, LLC[2]	18.00
The Dayton Power and Light Company[3]	4.90
Duke Energy Ohio, Inc.[4]	9.00
Energy Harbor Corp	4.85
Indiana Michigan Power Company[6]	7.85
Kentucky Utilities Company[5]	2.50
Louisville Gas and Electric Company[5]	5.63
Monongahela Power Company[1]	0.49
Ohio Power Company[6]	19.93
Peninsula Generation Cooperative[7]	6.65
Southern Indiana Gas and Electric Company[8]	1.50
	100.00

Some of the Common Stock issued in the name of:

*American Gas & Electric Company
**Columbus and Southern Ohio Electric Company

Subsidiary or affiliate of:

[1]FirstEnergy Corp.
[2]Buckeye Power, Inc.
[3]The AES Corporation
[4]Duke Energy Corporation
[5]PPL Corporation
[6]American Electric Power Company, Inc.
[7]Wolverine Power Supply Cooperative, Inc.
[8]CenterPoint Energy, Inc.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

A Message from the President

Ohio Valley Electric Corporation (OVEC) and its subsidiary, Indiana-Kentucky Electric Corporation (IKEC), achieved another year of improved unit availability, safety results and strong operating performance in 2019. Results are solely due to the great work of our employees and their efforts in creating a zero-harm culture, focusing on environmental stewardship, and using continuous improvement and LEAN tools to improve operating metrics and create cost optimization. OVEC-IKEC's strategic business plan continues to guide our efforts for "better" and improving our culture.

For 2020, we face the new challenge of COVID-19 and its impact on our business, our industry and our way of life. The OVEC-IKEC team has stepped up to this challenge. Our employees have shown amazing perseverance while working in this new environment and continue to remain focused on achieving our goals of being a safe, reliable and environmentally compliant provider of choice.

SAFETY

Our commitment to providing a safe and healthy place to work for all employees begins with ensuring that each employee returns home safely at the end of every day. Clifty Creek employees completed two years with no recordable injuries in March 2020. System Office employees have worked over 16 years without a lost-time injury. Electrical Operations have completed five years with no recordable injuries in April 2020. The company recordable and DART incident rates trended down in 2019 from the previous year, with year-end rates being 0.88 and 0.35, respectively. The goal is unchanged, zero-harm is the target.

Effective and quality coaching in the field continues as a focus with our ongoing Supervisor Field Observation safety training program. In alignment with Strategic Plan initiatives, a new safety training process including online training options is being to implemented to allow employees to receive key and required training in more than one format. In 2020, we will continue to strive to create and sustain a zero-harm culture for all working at OVEC-IKEC.

CULTURE

OVEC-IKEC remains on its continuous journey of culture improvement. Beginning in 2016, the company has seen significant improvement from the initial survey, with 2019 yielding a 15% improvement over 2018 results. OVEC-IKEC believes investing in culture improvement to engage our people will be the key to our long-term success. For 2020, an updated survey will allow our teams to continue to focus on opportunities and, with engagement of employees, create updated culture action plans to enable improvement.

RELIABILITY

In 2019, the combined equivalent availability of the five generating units at Kyger Creek and the six units at Clifty Creek was 78.2 percent compared with 76.6 percent in 2018. The combined equivalent forced outage rate (EFOR) at both plants was 5.8 percent in 2019 compared with 6.6 percent in 2018.

Through May 2020, the combined EFOR of the eleven generating units was 4 percent.

ENERGY SALES

OVEC's use factor — the ratio of power scheduled by the Sponsoring Companies to power available — for the combined on- and off-peak periods averaged 76.2 percent in 2019 compared with 84.2 percent in 2018. The on-peak use factor averaged 87.4 percent in 2019 compared with 92.1 percent in 2018. The off-peak use factor averaged 61.8 percent in 2019 and 74.0 percent in 2018.

In 2019, OVEC delivered 11.2 million megawatt hours (MWh) to the Sponsoring Companies under the terms of the Inter-Company Power Agreement compared with 11.8 million MWh delivered in 2018.

Power Costs

In 2019, OVEC's average power cost to the Sponsoring Companies was $57.04 per MWh compared with $54.29 per MWh in 2018. The total Sponsoring Company power costs were $641 million in 2019 compared with $644 million in 2018.

2020 Energy Sales Outlook

COVID-19's impact on an already depressed energy market has caused historically low energy prices and weak demand, which has resulted in reduced OVEC generation compared to traditional results. OVEC's total generation through June was approx. 3.9 million MWh compared to approximately 5.2 million MWh through June 2019. OVEC's updated projection for 2020, which assumes some incremental improvement in the energy demand by the end of the year, is projected at approximately 9 million MWh of generation.

Cost Control Initiatives

The OVEC and IKEC employees continue to strive to control costs and improve operating performance through application of its continuous improvement process (CIP). Since 2013, CIP has obtained over $26.5 million in sustainable savings through implementation of over 4,000 process improvements. Employee-driven process improvements and a continued effort in hands-on skill development with CIP and LEAN tools throughout the Company are driving the sustainability of the continuous improvement efforts.

In 2019, OVEC-IKEC continued utilizing the LEAN tool of Open Book Leadership (OBL) as a cost-control initiative to further improve our culture and overall business success. OBL is a management philosophy that focuses on empowering employees by providing them the information, education and communication necessary to understand how the Company performs and how they can impact that performance. The OBL process creates transparency of Company performance and engages employees in their ability to impact and improve key performance areas.

For 2020, OVEC is working to optimize operating cost and available generation, during this unprecedented time.

Environmental Compliance

OVEC-IKEC continues to maintain a strong commitment to meeting all applicable federal, state and local environmental rules and regulations. During 2019, OVEC operated in substantial compliance with the Mercury Air Toxics Standards (MATS), the Cross-State Air Pollution Rule (CSAPR) and other applicable state and federal air, water and solid waste regulations. In addition, for the third consecutive year, OVEC successfully met the challenge of operating in compliance with the more stringent ozone season NO_x constraints that went into effect with the 2017 ozone season with the adoption of EPA's CSAPR Update Rule. The Company is well positioned to continue to operate all SCR controlled units during 2020 and all future ozone seasons within the constraints of the current CSAPR Update Rule.

Clifty Creek and Kyger Creek both continue to sell nearly all of the gypsum produced at each plant into the wallboard market. Clifty Creek has also been successful in marketing some of its fly ash, and OVEC anticipates that market to continue to grow longer term. Kyger Creek will also pursue a marketing agreement for its dry fly ash in 2023 and beyond following the completion of the dry fly ash conversion project at that Station. Due to long-term market interest in gypsum, both plants have also been evaluating options to install barge loading facilities on-site that could provide additional benefits to fly ash and boiler slag marketing.

During the third year of the Trump Administration, there have been myriad regulatory actions and litigation involving several key environmental regulations impacting the electric utility sector. The regulatory actions include, but are not limited to, continued rulemaking on revising portions of the Steam Electric Effluent Limitations Guidelines (ELG) and associated compliance deadlines, further regulatory actions to the Coal Combustion Residuals (CCR) rule, and state regulatory action to implement the federal Affordable Clean Energy (ACE) rule. OVEC-IKEC will be engaging in multi-year environmental compliance activities to meet requirements in the new ELG and CCR rule revisions, anticipated to become final in 2020. OVEC will also continue to monitor and evaluate the impacts of the associated litigation involving these and other environmental rules impacting the utility sector.

In the interim, the Company continues to work toward meeting various compliance obligations associated with the current CCR rule, the current ELG rule applicable to dry fly ash conversion at the Kyger Creek Station and the Clean Water Act Section 316(b) regulations applicable to both facilities.

FirstEnergy Solutions Bankruptcy

On May 18, 2020, OVEC executed a settlement agreement (in the form of a joint stipulation) with Energy Harbor (formerly FirstEnergy Solutions) with respect to all claims in bankruptcy and related litigation. The settlement provided for Energy Harbor to pay OVEC $32.5 million to settle any cure costs associated with prior defaults and to assume its share (4.85%) of the Inter-Company Power Agreement (ICPA) as of June 1, 2020, and be obligated to perform its obligations under the ICPA going forward. The settlement agreement was approved by the Bankruptcy Court on June 15, 2020, and became fully effective on June 30, 2020.

Board of Directors and Officers Changes

On April 28, 2020, Mr. Dan Arbough, treasurer at LG&E and KU Energy, LLC, was elected a director of OVEC following the resignation of Mr. Paul W. Thompson. Mr. Thompson had served as an OVEC director since 2001. Also, Mr. Lonnie Bellar, Chief Operating Officer at LG&E and KU Energy, LLC, was appointed as a member of the Human Resource Committee, replacing Mr. Thompson.

Paul Chodak III

Paul Chodak
President

July 24, 2020

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
ASSETS		
ELECTRIC PLANT:		
At original cost	$ 2,793,490,793	$ 2,785,266,305
Less—accumulated provisions for depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	1,242,919,563	1,296,155,522
CURRENT ASSETS:		
Cash and cash equivalents	32,241,171	47,523,556
Accounts receivable	74,486,689	64,278,896
Fuel in storage	61,351,858	33,474,186
Emission allowances	291,681	298,355
Materials and supplies	40,931,063	40,634,643
Income taxes receivable	2,307,853	4,690,064
Property taxes applicable to future years	3,150,000	3,062,500
Prepaid expenses and other	2,817,715	2,175,905
Total current assets	217,578,030	196,138,105
REGULATORY ASSETS:		
Unrecognized postemployment benefits	5,201,536	4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	5,902,867
Total regulatory assets	37,371,844	43,945,148
DEFERRED CHARGES AND OTHER:		
Unamortized debt expense	688,643	156,683
Long-term investments	240,739,279	181,271,533
Income taxes receivable	2,307,341	4,614,683
Other	2,510,636	1,245,637
Total deferred charges and other	246,245,899	187,288,536
TOTAL	$ 1,744,115,336	$ 1,723,527,311

(Continued)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED BALANCE SHEETS
AS OF DECEMBER 31, 2019 AND 2018

	2019	2018
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $100 par value—authorized, 300,000 shares; outstanding, 100,000 shares in 2019 and 2018	$ 10,000,000	$ 10,000,000
Long-term debt	1,119,568,409	1,110,069,775
Line of credit borrowings	80,000,000	-
Retained earnings	17,294,023	14,238,732
Total capitalization	1,226,862,432	1,134,308,507
CURRENT LIABILITIES:		
Current portion of long-term debt	141,387,803	179,670,116
Line of credit borrowings	-	85,000,000
Accounts payable	34,871,926	41,313,387
Accrued other taxes	10,527,047	10,725,765
Regulatory liabilities	7,677,404	7,657,791
Accrued interest and other	27,532,934	20,663,191
Total current liabilities	221,997,114	345,030,250
COMMITMENTS AND CONTINGENCIES (Notes 3, 9, 11, and 12)		
REGULATORY LIABILITIES:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	-
Total regulatory liabilities	189,539,856	135,230,486
OTHER LIABILITIES:		
Pension liability	32,170,308	33,894,325
Asset retirement obligations	63,487,038	60,246,682
Postretirement benefits obligation	4,242,848	10,186,597
Postemployment benefits obligation	5,201,536	4,147,956
Other non-current liabilities	614,204	482,508
Total other liabilities	105,715,934	108,958,068
TOTAL	$ 1,744,115,336	$ 1,723,527,311

See notes to consolidated financial statements. (Concluded)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND RETAINED EARNINGS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
REVENUES FROM CONTRACTS WITH CUSTOMERS—Sales of electric energy to:		
Department of Energy	$ 4,641,167	$ 7,605,922
Sponsoring Companies	606,993,408	608,233,419
Other	3,033,066	-
Total revenues from contracts with customers	614,667,641	615,839,341
OPERATING EXPENSES:		
Fuel and emission allowances consumed in operation	274,843,402	277,368,623
Purchased power	3,735,333	6,863,294
Other operation	91,611,162	86,302,869
Maintenance	87,208,116	86,305,942
Depreciation	88,825,066	54,190,596
Taxes—other than income taxes	11,330,963	12,164,929
Income taxes	(2,912,531)	-
Total operating expenses	554,641,511	523,196,253
OPERATING INCOME (LOSS)	60,026,130	92,643,088
OTHER INCOME (EXPENSE)	24,280,007	(5,921,972)
INCOME BEFORE INTEREST CHARGES	84,306,137	86,721,116
INTEREST CHARGES:		
Amortization of debt expense	4,204,163	4,143,079
Interest expense	77,046,683	78,681,556
Total interest charges	81,250,846	82,824,635
NET INCOME	3,055,291	3,896,481
RETAINED EARNINGS—Beginning of year	14,238,732	10,342,251
RETAINED EARNINGS—End of year	$ 17,294,023	$ 14,238,732

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

	2019	2018
OPERATING ACTIVITIES:		
Net income	$ 3,055,291	$ 3,896,481
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation	88,825,066	54,190,596
Amortization of debt expense	4,204,163	4,143,079
Loss (gain) on marketable securities	(16,672,791)	13,147,621
Changes in assets and liabilities:		
Accounts receivable	(10,207,793)	(23,544,559)
Fuel in storage	(27,877,672)	342,925
Materials and supplies	(296,420)	(2,189,366)
Property taxes applicable to future years	(87,500)	(150,000)
Emissions allowances	6,674	57,497
Income tax receivable	2,382,211	65,545
Prepaid expenses and other	(641,810)	(123,945)
Other regulatory assets	9,392,126	(1,146,702)
Other noncurrent assets	1,042,342	(1,244,103)
Accounts payable	(5,360,967)	10,589,698
Accrued taxes	(198,718)	(148,768)
Accrued interest and other	6,869,743	(5,021,649)
Decommissioning, demolition and other	11,899,339	3,076,062
Other liabilities	(3,242,134)	(10,203,483)
Other regulatory liabilities	15,662,796	43,646,969
Net cash provided by operating activities	78,753,946	89,383,898
INVESTING ACTIVITIES:		
Electric plant additions	(12,474,714)	(8,439,941)
Proceeds from sale of long-term investments	55,360,283	71,570,881
Purchases of long-term investments	(98,155,238)	(111,716,117)
Net cash (used in) provided by investing activities	(55,269,669)	(48,585,177)
FINANCING ACTIVITIES:		
Debt issuance and maintenance costs	(3,849,380)	(529,670)
Repayment of Senior 2006 Notes	(22,029,278)	(20,798,412)
Repayment of Senior 2007 Notes	(15,648,462)	(14,759,418)
Repayment of Senior 2008 Notes	(16,992,682)	(15,926,263)
Reissuance 2009A Bonds	25,000,000	-
Redemption of 2009E Bonds	(100,000,000)	-
Issuance of 2019A Bonds	100,000,000	-
Proceeds from line of credit	10,000,000	-
Payments on line of credit	(15,000,000)	-
Principal payments under capital leases	(246,860)	(239,492)
Net cash (used in) provided by financing activities	(38,766,662)	(52,253,255)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(15,282,385)	(11,454,534)
CASH AND CASH EQUIVALENTS—Beginning of year	47,523,556	58,978,090
CASH AND CASH EQUIVALENTS—End of year	$ 32,241,171	$ 47,523,556
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid	$ 75,703,531	$ 81,777,903
Income taxes (received) paid—net	$ (4,690,064)	$ (74,784)
Non-cash electric plant additions included in accounts payable at December 31	$ 58,516	$ 892,150

See notes to consolidated financial statements.

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

1. ORGANIZATION AND SIGNIFICANT ACCOUNTING POLICIES

Consolidated Financial Statements—The consolidated financial statements include the accounts of Ohio Valley Electric Corporation (OVEC) and its wholly owned subsidiary, Indiana-Kentucky Electric Corporation (IKEC), collectively, the Companies. All intercompany transactions have been eliminated in consolidation.

Organization—The Companies own two generating stations located in Ohio and Indiana with a combined electric production capability of approximately 2,256 megawatts. OVEC is owned by several investor-owned utilities or utility holding companies and two affiliates of generation and transmission rural electric cooperatives. These entities or their affiliates comprise the Sponsoring Companies. The Sponsoring Companies purchase power from OVEC according to the terms of the Inter-Company Power Agreement (ICPA), which has a current termination date of June 30, 2040. Approximately 24% of the Companies' employees are covered by a collective bargaining agreement that expires on August 31, 2021.

Prior to 2004, OVEC's primary commercial customer was the U.S. Department of Energy (DOE). The contract to provide OVEC-generated power to the DOE was terminated in 2003 and all obligations were settled at that time. Currently, OVEC has an agreement to arrange for the purchase of power (Arranged Power), under the direction of the DOE, for resale directly to the DOE. The current agreement with the DOE was executed on July 11, 2018, for one year, with the option for the DOE to extend the agreement at the anniversary date. The agreement was extended on July 11, 2019, for one year. OVEC anticipates that this agreement will continue until 2022. All purchase costs are billable by OVEC to the DOE.

Rate Regulation—The proceeds from the sale of power to the Sponsoring Companies are designed to be sufficient for OVEC to meet its operating expenses and fixed costs, as well as earn a return on equity before federal income taxes. In addition, the proceeds from power sales are designed to cover debt amortization and interest expense associated with financings. The Companies have continued and expect to continue to operate pursuant to the cost-plus rate of return recovery provisions at least to June 30, 2040, the date of termination of the ICPA. In 2014, to promote reduced costs, the Companies reduced their billings under the ICPA to effectively forego recovery of the equity return through the ICPA billings. However, in 2018, the Companies discontinued this practice and are once again recovering the equity return through the ICPA billings.

The accounting guidance for Regulated Operations provides that rate-regulated utilities account for and report assets and liabilities consistent with the economic effect of the way in which rates are established, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged and collected. The Companies follow the accounting and reporting requirements in accordance with the guidance for Regulated Operations. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred in the accompanying consolidated balance sheets and are recognized as income as the related amounts are included in service rates and recovered from or refunded to customers.

The Companies' regulatory assets, liabilities, and amounts authorized for recovery through Sponsor billings at December 31, 2019 and 2018, were as follows:

	2019	2018
Regulatory assets:		
Noncurrent regulatory assets:		
Unrecognized postemployment benefits	$ 5,201,536	$ 4,147,956
Unrecognized pension benefits	32,170,308	33,894,325
Decommissioning, demolition and other	-	8,721,689
Total	37,371,844	46,763,970
Total regulatory assets	$ 37,371,844	$ 46,763,970
Regulatory liabilities:		
Current regulatory liabilities:		
Deferred revenue—advances for construction	$ 6,182,811	$ 6,024,309
Deferred credit—advance collection of interest	1,494,593	1,633,482
Total	7,677,404	7,657,791
Noncurrent regulatory liabilities:		
Postretirement benefits	76,162,798	63,659,058
Income taxes refundable to customers	8,658,897	11,571,428
Advance billing of debt reserve	90,000,000	60,000,000
Decommissioning, demolition and other	14,718,161	2,818,822
Total	189,539,856	138,049,308
Total regulatory liabilities	$ 197,217,260	$ 145,707,099

Regulatory Assets—Regulatory assets consist primarily of pension benefit costs, postemployment benefit costs, and accrued decommissioning and demolition costs to be billed to the Sponsoring Companies in future years. The Companies' current billing policy for pension and postemployment benefit costs is to bill its actual plan funding.

Regulatory Liabilities—The regulatory liabilities classified as current in the accompanying consolidated balance sheet as of December 31, 2019, consist primarily of interest expense collected from customers in advance of expense recognition and customer billings for construction in progress. These amounts will be credited to customer bills during 2020. Other regulatory liabilities consist primarily of postretirement benefit costs and decommissioning and demolition costs that have been billed to customers in excess of cumulative expense recognition, income taxes refundable to customers that will be credited to bills over a long-term basis, and advanced billings collected from the Sponsoring Companies for debt service.

The regulatory liability for postretirement benefits recorded at December 31, 2019 and 2018, represents amounts collected in historical billings in excess of the accounting principles generally accepted in the United States of America (GAAP) net periodic benefit costs, including a termination payment from the DOE in 2003 for unbilled postretirement benefit costs, and incremental unfunded plan obligations recognized in the balance sheets but not yet recognizable in GAAP net periodic benefit costs. Related regulatory liabilities are being credited to customer bills on a long-term basis.

In January 2017, the Companies started advance billing the Sponsoring Companies for debt service as allowed under the ICPA. As of December 31, 2019 and 2018, $90 million and $60 million, respectively, had been advance billed to the Sponsoring Companies. As the Companies have not yet incurred the related costs, a regulatory liability was recorded which will be credited to customer bills on a long-term basis.

Cash and Cash Equivalents—Cash and cash equivalents primarily consist of cash and money market funds and their carrying value approximates fair value. For purposes of these statements, the Companies consider temporary cash investments to be cash equivalents since they are readily convertible into cash and have original maturities of less than three months.

Electric Plant—Property additions and replacements are charged to utility plant accounts. Depreciation expense is recorded at the time property additions and replacements are billed to customers or at the date the property is placed in service if the in-service date occurs subsequent to the customer billing. Customer billings for construction in progress are recorded as deferred revenue—advances for construction. These amounts are closed to revenue at the time the related property is placed in service. Depreciation expense and accumulated depreciation are recorded when financed property additions and replacements are recovered over a period of years through customer debt retirement billing. All depreciable property will be fully billed and depreciated prior to the expiration of the ICPA. Repairs of property are charged to maintenance expense.

Fuel in Storage, Emission Allowances, and Materials and Supplies—The Companies maintain coal, reagent, and oil inventories, as well as emission allowances, for use in the generation of electricity for regulatory compliance purposes due to the generation of electricity. These inventories are valued at average cost. Materials and supplies consist primarily of replacement parts necessary to maintain the generating facilities and are valued at average cost.

Long-Term Investments—Long-term investments consist of marketable securities that are held for the purpose of funding decommissioning and demolition costs, debt service, potential postretirement funding, and other costs. These debt securities have been classified as trading securities in accordance with the provisions of the accounting guidance for Investments—Debt and Equity Securities. Debt and equity securities reflected in long-term investments are carried at fair value with the unrealized gain or loss, reported in Other Income (Expense). The cost of securities sold is based on the specific identification cost method. The fair value of most investment securities is determined by reference to currently available market prices. Where quoted market prices are not available, the Companies use the market price of similar types of securities that are traded in the market to estimate fair value. See Fair Value Measurements in Note 10. Long-term investments primarily consist of municipal bonds, money market mutual fund investments, and mutual funds. Net unrealized gains (losses) recognized during 2019 and 2018 on securities still held at the balance sheet date were $16,445,716 and ($12,968,851), respectively.

Fair Value Measurements of Assets and Liabilities—The accounting guidance for Fair Value Measurements and Disclosures establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements). Where observable inputs are available, pricing may be completed using comparable securities, dealer values, and general market conditions to determine fair value. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, and other observable inputs for the asset or liability.

Unamortized Debt Expense—Unamortized debt expense relates to costs incurred in connection with obtaining revolving credit agreements. These costs are being amortized over the term of the related revolving credit agreement and are recorded as an asset in the consolidated balance sheets. Costs incurred to issue debt are recorded as a reduction to long-term debt as presented in Note 6.

Asset Retirement Obligations and Asset Retirement Costs—The Companies recognize the fair value of legal obligations associated with the retirement or removal of long-lived assets at the time the obligations are incurred and can be reasonably estimated. The initial recognition of this liability is accompanied by a corresponding increase in depreciable electric plant. Subsequent to the initial recognition, the liability is adjusted for any revisions to the expected value of the retirement obligation (with corresponding adjustments to electric plant) and for accretion of the liability due to the passage of time.

These asset retirement obligations are primarily related to obligations associated with future asbestos abatement at certain generating stations and certain plant closure costs, including the impacts of the coal combustion residuals rule.

Balance—January 1, 2018	$ 57,170,620
Accretion	3,076,062
Liabilities settled	-
Revisions to cash flows	-
Balance—December 31, 2018	60,246,682
Accretion	3,275,262
Liabilities settled	(34,906)
Revisions to cash flows	-
Balance—December 31, 2019	$ 63,487,038

During 2017, the Companies completed an updated study to estimate the asset retirement costs described above. The revised estimated costs are recorded in the accompanying balance sheets. Adjustments resulting from the revised estimated costs are included as revisions to cash flows in the above table. The increase in the asset retirement obligation is primarily the result of proposed regulations related to the disposal of coal combustion residuals, as further discussed in Note 9.

The Companies do not recognize liabilities for asset retirement obligations for which the fair value cannot be reasonably estimated. The Companies have asset retirement obligations associated with transmission assets. However, the retirement date for these assets cannot be determined; therefore, the fair value of the associated liability currently cannot be estimated and no amounts are recognized in the consolidated financial statements herein.

Income Taxes—The Companies use the liability method of accounting for income taxes. Under the liability method, the Companies provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities, which will result in a future tax consequence. The Companies account for uncertain tax positions in accordance with the accounting guidance for Income Taxes.

Use of Estimates—The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenue Recognition—In May 2014, the FASB issued Revenue from Contracts with Customers, Topic 606 (ASU No. 2014-09), which provides a new framework for the recognition of revenue. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The Companies implemented the guidance on a modified retrospective basis on January 1, 2018. Revenue for the reporting periods beginning after December 31, 2017, are recorded and disclosed in accordance with Topic 606, while prior period results have not been adjusted and continue to be reported in accordance with prior accounting guidance. The Companies did not make any adjustments to the January 1, 2018, opening balances as a result of adoption, and the implementation had no impact on the Companies’ consolidated financial statements.

Performance obligations related to the sale of electric energy are satisfied over time as system resources are made available to customers and as energy is delivered to customers and the Companies recognize revenue upon billing the customer.

The Companies have three contracts with customers resulting in three types of revenue. These three contracted revenue types are:

1) Sales of Electric Energy to Department of Energy
2) Sales of Electric Energy to Sponsoring Companies
3) Sales of Electric Energy to Pennsylvania, Jersey, Maryland Power Pool (PJM)

The performance obligations and recognition of revenue are similar and both individually and, in the aggregate, were not materially impacted by the implementation of Topic 606. The Companies have no contract assets or liabilities as of December 31, 2019. The following table provides information about the Companies' receivables and unbilled revenue from contracts with customers:

	Accounts Receivable	Unbilled
Beginning balance as of January 1, 2018	$ 40,737,337	$ 5,454,632
Ending balance as of December 31, 2018	64,278,896	5,098,515
Increase/(decrease)	$ 23,544,559	$ (356,117)
Beginning balance as of January 1, 2019	$ 64,278,896	$ 5,098,515
Ending balance as of December 31, 2019	$ 74,486,689	$ 5,611,960
Increase/(decrease)	$ 10,207,793	$ 513,445

Recently Issued Accounting Standards—In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*. The pronouncement changes the impairment model for most financial assets, replacing the current "incurred loss" model. ASU 2016-13 will require the use of an "expected loss" model for instruments measured at amortized cost and will also require entities to record allowances for available-for-sale debt securities rather than reduce the carrying amount. The Companies plan to adopt the standard for the fiscal year ended December 31, 2020. The Companies are in the process of evaluating the impact of adoption, if any, of this ASU on the Companies' consolidated financial statements.

See adoption of ASC 842, *Leases*, in Note 11.

Subsequent Events—In preparing the accompanying financial statements and disclosures, the Companies reviewed subsequent events through April 17, 2020, which is the date the consolidated financial statements were issued.

Subsequent to December 31, 2019, the World Health Organization declared the ongoing expansion of an existing outbreak of the SARS-CoV-2 virus, named the coronavirus 2019 ("COVID-19"), a pandemic. As a result of the evolving situation and increasing number of cases, many countries have taken various steps in an attempt to curtail or slow COVID-19's spread, including limiting or ceasing international and domestic travel, slowing or ceasing production activity, and lockdowns or shelter-in-place orders. The Companies are currently unable to predict the duration or extent of any business disruption, changes in law and/or regulation, and uncertainty regarding government and regulatory policy that may occur as a result of these events. COVID-19 has also caused significant volatility and declines in value to most financial markets, which will have a near-term impact on the value of the Companies' long-term investments and investments related to benefit obligations. As there are no comparable recent events which may provide guidance as to the effect of the spread of

COVID-19, the Companies are unable to estimate the impact that COVID-19 will have on its financial results at this time.

2. RELATED-PARTY TRANSACTIONS

Transactions with the Sponsoring Companies during 2019 and 2018 included the sale of all generated power to them, the purchase of Arranged Power from them, and other utility systems in order to meet the DOE's power requirements, contract barging services, railcar services, and minor transactions for services and materials. The Companies have Power Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, Kentucky Utilities Company, Ohio Edison Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies; and Transmission Service Agreements with Louisville Gas and Electric Company, Duke Energy Ohio, Inc., The Dayton Power and Light Company, The Toledo Edison Company, Ohio Edison Company, Kentucky Utilities Company, and American Electric Power Service Corporation as agent for the American Electric Power System Companies.

At December 31, 2019 and 2018, balances due from the Sponsoring Companies are as follows:

	2019	2018
Accounts receivable	$ 66,926,922	$ 57,442,759

During 2019 and 2018, American Electric Power accounted for approximately 44% of operating revenues from Sponsoring Companies and Buckeye Power accounted for 18%. No other Sponsoring Company accounted for more than 10%.

American Electric Power Company, Inc. and subsidiary companies owned 43.47% of the common stock of OVEC as of December 31, 2019. The following is a summary of the principal services received from the American Electric Power Service Corporation as authorized by the Companies' Boards of Directors:

	2019	2018
General services	$ 4,830,104	$ 4,917,608
Specific projects	119,157	472,862
Total	$ 4,949,261	$ 5,390,470

General services consist of regular recurring operation and maintenance services. Specific projects primarily represent nonrecurring plant construction projects and engineering studies, which are approved by the Companies' Boards of Directors. The services are provided in accordance with the service agreement dated December 15, 1956, between the Companies and the American Electric Power Service Corporation.

3. COAL SUPPLY

The Companies have coal supply agreements with certain nonaffiliated companies that expire at various dates from the year 2020 through 2022. Pricing for coal under these contracts is subject to contract provisions and adjustments. The Companies currently have 100% of their 2020 coal requirements under contract. These contracts are based on rates in effect at the time of contract execution. Our total obligations under these agreements as of December 31, 2019, are included in the table below:

2020	$ 213,126,750
2021	$ 135,876,000
2022	$ 50,340,000

4. ELECTRIC PLANT

Electric plant at December 31, 2019 and 2018, consists of the following:

	2019	2018
Steam production plant	$2,698,568,508	$2,690,743,500
Transmission plant	81,986,558	81,578,790
General plant	12,909,163	12,917,451
Intangible	26,564	26,564
	2,793,490,793	2,785,266,305
Less accumulated depreciation	1,563,780,062	1,500,183,895
	1,229,710,731	1,285,082,410
Construction in progress	13,208,832	11,073,112
Total electric plant	$1,242,919,563	$1,296,155,522

All property additions and replacements are fully depreciated on the date the property is placed in service, unless the addition or replacement relates to a financed project. As the Companies' policy is to bill in accordance with the debt service schedule under the debt agreements, all financed projects are being depreciated in amounts equal to the principal payments on outstanding debt.

5. BORROWING ARRANGEMENTS AND NOTES

OVEC had a $200 million revolving credit facility set to expire in November 2019, which was replaced on April 25, 2019, by a new revolving credit facility of $185 million with an expiration date of April 25, 2022. At December 31, 2019 and 2018, OVEC had borrowed $80 million and $85 million, respectively, under lines of credit. Interest expense related to lines of credit borrowings was $3,757,148 in 2019 and $3,448,137 in 2018. During 2019 and 2018, OVEC incurred annual commitment fees of $268,285 and $318,885, respectively, based on the borrowing limits of the lines of credit.

6. LONG-TERM DEBT

The following amounts were outstanding at December 31, 2019 and 2018:

	Interest Rate Type	Interest Rate	2019	2018
Senior 2006 Notes:				
2006A due February 15, 2026	Fixed	5.80 %	$ 168,569,904	$ 189,381,919
2006B due June 15, 2040	Fixed	6.40	54,142,874	55,360,136
Senior 2007 Notes:				
2007A-A due February 15, 2026	Fixed	5.90	74,610,818	84,386,325
2007A-B due February 15, 2026	Fixed	5.90	18,790,003	21,251,868
2007A-C due February 15, 2026	Fixed	5.90	18,939,620	21,421,088
2007B-A due June 15, 2040	Fixed	6.50	27,012,831	27,630,240
2007B-B due June 15, 2040	Fixed	6.50	6,802,916	6,958,404
2007B-C due June 15, 2040	Fixed	6.50	6,857,084	7,013,810
Senior 2008 Notes:				
2008A due February 15, 2026	Fixed	5.92	23,292,665	26,342,332
2008B due February 15, 2026	Fixed	6.71	47,301,931	53,467,070
2008C due February 15, 2026	Fixed	6.71	49,367,759	55,446,166
2008D due June 15, 2040	Fixed	6.91	39,387,935	40,230,351
2008E due June 15, 2040	Fixed	6.91	40,072,323	40,929,376
Series 2009 Bonds:				
2009A due February 15, 2026	Fixed	2.88	25,000,000	-
2009B due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009C due February 1, 2026	Floating	3.31	25,000,000	25,000,000
2009D due February 1, 2026	Floating	1.46	25,000,000	25,000,000
2009E due October 1, 2019	Fixed	5.63	-	100,000,000
Series 2010 Bonds:				
2010A due February 1, 2040	Floating	6.23	50,000,000	50,000,000
2010B due February 1, 2040	Floating	3.31	50,000,000	50,000,000
Series 2012 Bonds:				
2012A due June 1, 2032	Fixed	5.00	76,800,000	76,800,000
2012A due June 1, 2039	Fixed	5.00	123,200,000	123,200,000
2012B due June 1, 2040	Floating	6.23	50,000,000	50,000,000
2012C due June 1, 2040	Floating	6.23	50,000,000	50,000,000
Series 2017 Notes:				
2017A due August 4, 2022	Floating	6.23	100,000,000	100,000,000
Series 2019 Bonds:				
2019A due September 1, 2029	Fixed	3.25	100,000,000	-
Total debt			1,275,148,663	1,304,819,085
Total premiums and discounts (net)			(437,865)	(460,465)
Less unamortized debt expense			(13,754,586)	(14,618,729)
Total debt net of premiums, discounts, and unamortized debt expense			1,260,956,212	1,289,739,891

All of the OVEC amortizing unsecured senior notes have maturities scheduled for February 15, 2026, or June 15, 2040, as noted in the previous table.

In 2009, the Ohio Air Quality Development Authority (the "OAQDA") issued the variable-rate, non-amortizing, tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) in four series (Series 2009A, Series 2009B, Series 2009C and Series 2009D) of $25 million each (the "Series 2009A Bonds," the "Series 2009B Bonds," the "Series 2009C Bonds" and the "Series 2009D Bonds") and $100 million fixed-rate non-amortizing tax-exempt State of Ohio Air Quality Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2009E Bonds"), the proceeds of which were used to finance a portion of OVEC's costs of acquiring, constructing and installing certain solid waste disposal facilities comprising "air quality facilities," as defined in Chapter 3706, Ohio Revised Code, as amended, for Units 1-5 of the Kyger Creek Plant. OVEC is obligated to make payments under loan agreements between OVEC and OAQDA equal to the principal and interest payments due on such bonds, among other payments.

The Series 2009B and Series 2009C Bonds were remarketed in August 2016, for a five-year interest period that extends to August 25, 2021. The Series 2009A Bonds were secured by an irrevocable transferable direct-pay letter of credit at December 31, 2016, but were repurchased by OVEC on February 6, 2017. Further, the Series 2009D Bonds were secured by an irrevocable transferable direct-pay letter of credit that expired on November 14, 2019. On August 14, 2019, the Series 2009A Bonds and Series 2009D Bonds were each reoffered with a fixed interest rate of 2.875% per annum for the period beginning on August 28, 2019 and ending on February 1, 2026. In addition, the Series 2009E Bonds, which were scheduled to mature on October 1, 2019, were refunded with the proceeds of the Series 2019A Bonds (as defined below).

In December 2010, OVEC established a borrowing facility under which OVEC borrowed, in 2011, $100 million variable-rate bonds due on February 1, 2040. In June 2011, the $100 million variable-rate bonds were reissued by the Indiana Finance Authority (the "IFA") as two series of $50 million variable-rate, non-amortizing, tax-exempt bonds: the Series 2010A Bonds, with an interest period of three years and the Series 2010B Bonds, with an interest period of five years. The Series 2010B Bonds were remarketed in August 2016 for another five-year interest period ending on August 25, 2021. The Series 2010A Bonds were remarketed in June 2014 for a three-year period and in September 2017 for another three-year period that extends to August 4, 2020. The Series 2010A Bonds are to be refinanced in 2020. The Series 2010B Bonds are not being reoffered at this time.

During 2012, the IFA issued $200 million fixed-rate, tax-exempt Midwestern Disaster Relief Revenue Bonds (Ohio Valley Electric Corporation Project) (the "Series 2012A Bonds") and two series of $50 million each, variable-rate, tax-exempt bonds: the Series 2012B Bonds and the Series 2012C Bonds. The Series 2012A Bonds will begin amortizing on June 1, 2027, up to its maturity date. OVEC is obligated to make payments under loan agreements between OVEC and the IFA equal to the principal and interest payments due on such bonds, among other payments.

In 2017, the Series 2012B Bonds and the Series 2012C Bonds, which had been secured by irrevocable transferable direct-pay letters of credit, were remarketed with four-year and five-year interest periods expiring August 4, 2021 and August 4, 2022, respectively.

During 2017, OVEC issued $100 million 2017A variable-rate non-amortizing unsecured senior notes ("2017A Notes") to refinance and retire a 2013 series of notes ("2013A Notes"). The 2013A Notes had an original maturity date of February 15, 2018. The 2017A Notes have an annual repayment of $33,333,333 on August 4, 2020, August 4, 2021, and at the maturity date of August 4, 2022.

In August 2019, OVEC refinanced or refunded $150 million in tax-exempt bonds as follows: (i) the OAQDA issued the State of Ohio Air Quality Revenue Refunding Bonds (Ohio Valley Electric Corporation Project), Series 2019A in an aggregate principal amount of $100 million (the "Series 2019A Bonds"), with a fixed interest rate of 3.25% per annum for the period beginning August 28, 2019 to September 1, 2029, the proceeds of which were used to refund the Series 2009E Bonds, (ii) the Series 2009A Bonds were reoffered in an aggregate principal amount of $25 million and (iii) the Series 2009D Bonds were reoffered in an aggregate principal amount of $25 million.

The annual maturities of long-term debt as of December 31, 2019, are as follows:

2020	$ 141,387,803
2021	244,982,570
2022	148,800,891
2023	69,523,395
2024	73,831,592
2025–2040	596,622,412
Total	$1,275,148,663

Note that the 2020 maturities of long-term debt include $50 million variable-rate bonds with agreements expiring in August 2020.

7. INCOME TAXES

OVEC and IKEC file a consolidated federal income tax return. The effective tax rate varied from the statutory federal income tax rate due to differences between the book and tax treatment of various transactions as follows:

	2019	2018
Income tax expense at statutory rate (21% 2019, 21% 2018)	$ 29,980	$ 818,261
Temporary differences flowed through to customer bills	(2,948,492)	(823,343)
Permanent differences and other	5,981	5,082
Income tax provision	$ (2,912,531)	$ -

Components of the income tax provision were as follows:

	2019	2018
Current income tax expense—federal	$ (2,912,531)	$ -
Current income tax (benefit)/expense—state	-	-
Deferred income tax expense/(benefit)—federal	-	-
Total income tax provision	$ (2,912,531)	$ -

OVEC and IKEC record deferred tax assets and liabilities based on differences between book and tax basis of assets and liabilities measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Deferred tax assets and liabilities are adjusted for changes in tax rates.

To the extent that the Companies have not reflected credits in customer billings for deferred tax assets, they have recorded a regulatory liability representing income taxes refundable to customers under the applicable agreements among the parties. These temporary differences will be credited to the Sponsoring Companies through future power billings. The regulatory liability was $8,658,898 and $11,571,429 at December 31, 2019 and 2018, respectively.

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Deferred income tax assets (liabilities) at December 31, 2019 and 2018, consisted of the following:

	2019	2018
Deferred tax assets:		
Deferred revenue—advances for construction	$ 1,299,537	$ 1,265,885
Federal net operating loss carryforwards	39,691,784	49,663,022
Postretirement benefit obligation	891,785	2,140,505
Pension liability	7,034,974	6,447,661
Postemployment benefit obligation	1,093,288	871,608
Asset retirement obligations	13,344,057	12,659,609
Advanced collection of interest and debt service	19,230,828	12,951,016
Miscellaneous accruals	1,154,630	1,183,464
Regulatory liability—postretirement benefits	16,008,318	13,376,650
Regulatory liability—asset retirement costs	3,093,544	-
Regulatory liability—income taxes refundable to customers	4,549,301	5,484,284
Total deferred tax assets	107,392,046	106,043,704
Deferred tax liabilities:		
Prepaid expenses	(384,597)	(352,638)
Electric plant	(81,887,070)	(81,674,810)
Unrealized gain/loss on marketable securities	(4,348,230)	(855,225)
Regulatory asset—pension benefits	(6,719,696)	(7,122,200)
Regulatory asset—asset retirement costs	-	(1,240,367)
Regulatory asset—unrecognized postemployment benefits	(1,093,288)	(871,608)
Total deferred tax liabilities	(94,432,881)	(92,116,848)
Valuation allowance	(12,959,165)	(13,926,856)
Deferred income tax assets	$ -	$ -

Because future taxable income may prove to be insufficient to recover the Companies' deferred tax assets, the Companies have recorded a valuation allowance for their deferred tax assets as of December 31, 2019 and 2018. During 2016, due to a change in federal tax law, the Companies recorded as receivables certain AMT credit carryforwards that the Companies expect to claim as refundable credits in their 2018–2022 federal income tax returns. The amount of the refundable AMT credit is reflected as a current receivable of $2,307,341 and a non-current receivable of $2,307,341 for a total receivable of $4,614,682.

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The accounting guidance for Income Taxes addresses the determination of whether the tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under this guidance, the Companies may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The Companies have not identified any uncertain tax positions as of December 31, 2019 and 2018, and accordingly, no liabilities for uncertain tax positions have been recognized.

The Companies file income tax returns with the Internal Revenue Service and the states of Ohio, Indiana, and the Commonwealth of Kentucky. The Companies are no longer subject to federal tax examinations for tax years 2015 and earlier. The Companies are no longer subject to State of Indiana tax examinations for tax years 2015 and earlier. The Companies are no longer subject to Ohio and the Commonwealth of Kentucky examinations for tax years 2014 and earlier. The Companies have $189,008,494 of Federal Net Operating Loss carryovers that begin to expire in 2032.

8. PENSION PLAN AND OTHER POSTRETIREMENT AND POSTEMPLOYMENT BENEFITS

The Companies have a noncontributory qualified defined benefit pension plan (the Pension Plan) covering substantially all of their employees hired prior to January 1, 2015. The benefits are based on years of service and each employee’s highest consecutive 36-month compensation period. Employees are vested in the Pension Plan after five years of service with the Companies.

Funding for the Pension Plan is based on actuarially determined contributions, the maximum of which is generally the amount deductible for income tax purposes and the minimum being that required by the Employee Retirement Income Security Act of 1974, as amended.

In addition to the Pension Plan, the Companies provide certain health care and life insurance benefits (Other Postretirement Benefits) for retired employees. Substantially, all of the Companies’ employees hired prior to January 1, 2015, become eligible for these benefits if they reach retirement age while working for the Companies. These and similar benefits for active employees are provided through employer funding and insurance policies. In December 2004, the Companies established VEBA trusts. In January 2011, the Companies established an Internal Revenue Code Section 401(h) account under the Pension Plan.

The full cost of the pension benefits and other postretirement benefits has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 56% and 44% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 57% and 43% split between OVEC and IKEC, respectively, as of December 31, 2018.

The Pension Plan’s assets as of December 31, 2019, consist of investments in equity and debt securities. All of the trust funds’ investments for the pension and postemployment benefit plans

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are diversified and managed in compliance with all laws and regulations. Management regularly reviews the actual asset allocation and periodically rebalances the investments to targeted allocation when appropriate. The investments are reported at fair value under the Fair Value Measurements and Disclosures accounting guidance.

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies, and target asset allocations by plan. Benefit plan assets are reviewed on a formal basis each quarter by the OVEC-IKEC Qualified Plan Trust Committee.

The investment philosophies for the benefit plans support the allocation of assets to minimize risks and optimize net returns.

Investment strategies include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs, and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style neutral to limit volatility compared to applicable benchmarks.

The target asset allocation for each portfolio is as follows:

Pension Plan Assets	**Target**
Domestic equity	15 %
International and global equity	15
Fixed income	68
Cash	2

VEBA Plan Assets	**Target**
Domestic equity	20 %
International and global equity	20
Fixed income	60

Each benefit plan contains various investment limitations. These limitations are described in the investment policy statement and detailed in customized investment guidelines. These investment guidelines require appropriate portfolio diversification and define security concentration limits. Each investment manager's portfolio is compared to an appropriate diversified benchmark index.

Equity investment limitations:

- No security in excess of 5% of all equities.

- Cash equivalents must be less than 10% of each investment manager's equity portfolio.
- Individual securities must be less than 15% of each manager's equity portfolio.
- No investment in excess of 5% of an outstanding class of any company.
- No securities may be bought or sold on margin or other use of leverage.

Fixed-Income Limitations—As of December 31, 2019, the Pension Plan fixed-income allocation consists of managed accounts composed of U.S. Government, corporate, and municipal obligations. The VEBA benefit plans' fixed-income allocation is composed of a variety of fixed-income securities and mutual funds. Investment limitations for these fixed-income funds are defined by manager prospectus.

Cash Limitations—Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments, including money market mutual funds, certificates of deposit, treasury bills, and other types of investment-grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Projected Pension Plan and Other Postretirement Benefits obligations and funded status as of December 31, 2019 and 2018, are as follows:

	Pension Plan		Other Postretirement Benefits	
	2019	2018	2019	2018
Change in projected benefit obligation:				
Projected benefit obligation—beginning of year	$ 234,099,137	$ 256,019,423	$ 151,305,246	$ 168,487,209
Service cost	6,078,450	7,108,309	3,428,368	4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Net actuarial loss (gain)	30,255,836	(28,186,233)	21,462	(17,121,066)
Plan amendments (1) (2)		-	3,989,560	(6,648,237)
Settlement (3)	(27,857,703)	-	-	-
Expenses paid from assets	(36,469)	(46,647)	-	-
Projected benefit obligation—end of year	244,541,899	234,099,137	159,833,696	151,305,246
Change in fair value of plan assets:				
Fair value of plan assets—beginning of year	200,204,812	218,769,576	141,118,649	151,290,524
Actual return on plan assets	42,540,447	(14,277,140)	19,940,452	(6,304,997)
Expenses paid from assets	(36,469)	(46,647)	-	-
Employer contributions	5,600,000	6,000,000	13,853	40,099
Plan participants' contributions		-	1,312,941	1,363,566
Benefits paid	(8,079,496)	(10,240,977)	(6,795,047)	(5,270,543)
Settlement	(27,857,703)	-	-	-
Fair value of plan assets—end of year	212,371,591	200,204,812	155,590,848	141,118,649
Underfunded status—end of year	$ (32,170,308)	$ (33,894,325)	$ (4,242,848)	$ (10,186,597)

(1) The $3.9M plan amendment is the result of the change of the long-term retiree cost sharing through retiree contributions for pre-65 retirees from 20% to 12%.

(2) The $6.6M plan amendment is the result of the termination of the active/pre-65 retiree PPO and indemnity plans. All participants in those plans were moved to the CDHP.

(3) The $27.9M settlement is the result of an annuity purchase of about $22.7M for 162 retirees and beneficiaries which was paid on November 25, 2019 and the lump sums payments totaling about $5.2M during 2019.

See Note 1 for information regarding regulatory assets related to the Pension Plan and Other Postretirement Benefits plan.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

The accumulated benefit obligation for the Pension Plan was $218,590,886 and $212,367,000 at December 31, 2019 and 2018, respectively.

Components of Net Periodic Benefit Cost—The Companies record the expected cost of Other Postretirement Benefits over the service period during which such benefits are earned.

Pension expense is recognized as amounts are contributed to the Pension Plan and billed to customers. The accumulated difference between recorded pension expense and the yearly net periodic pension expense, as calculated under generally accepted accounting principles, is billable as a cost of operations under the ICPA when contributed to the pension fund. This accumulated difference has been recorded as a regulatory asset in the accompanying consolidated balance sheets.

	Pension Plan		Other Postretirement Benefits	
	2019	2018	2019	2018
Service cost	$ 6,078,450	$ 7,108,309	$ 3,428,368	$ 4,297,973
Interest cost	10,082,144	9,445,262	6,571,166	6,196,344
Expected return on plan assets	(11,867,776)	(13,034,239)	(7,515,431)	(8,062,728)
Amortization of prior service cost	(416,565)	(416,565)	(3,145,420)	(2,536,062)
Recognized actuarial loss (gain)	1,234,195	1,049,337	-	-
Cost of Settlements	3,570,924	-	-	-
Total benefit cost	$ 8,681,372	$ 4,152,104	$ (661,317)	$ (104,473)
Pension and other postretirement benefits expense recognized in the consolidated statements of income and retained earnings and billed to Sponsoring Companies under the ICPA	$ 5,600,000	$ 6,000,000	$ -	$ -

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

The following table presents the classification of Pension Plan assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
Common stock	$ 8,792,346	$ -	$ -	$ 8,792,346
Equity mutual funds	42,776,633	-	-	42,776,633
Index futures	-	230	-	230
Fixed-income securities	-	140,413,999	-	140,413,999
Commodities	-	43	-	43
Cash equivalents	7,154,484	-	-	7,154,484
Subtotal benefit plan assets	$ 58,723,463	$ 140,414,272	$ -	199,137,735
Investments measured at net asset value (NAV)				13,233,857
Total benefit plan assets				$ 212,371,592
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Common stock	$ 7,138,880	$ -	$ -	$ 7,138,880
Equity mutual funds	35,494,238	-	-	35,494,238
Index futures	-	81	-	81
Fixed-income securities	-	142,452,199	-	142,452,199
Commodities	-	47	-	47
Cash equivalents	3,719,257	-	-	3,719,257
Subtotal benefit plan assets	$ 46,352,375	$ 142,452,327	$ -	188,804,702
Investments measured at net asset value (NAV)				11,400,110
Total benefit plan assets				$ 200,204,812

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

The following table presents the classification of VEBA and 401(h) account assets within the fair value hierarchy at December 31, 2019 and 2018:

	Fair Value Measurements at Reporting Date Using			
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**2019 Total**
Equity mutual funds	$ 54,952,087	$ -	$ -	$ 54,952,087
Fixed-income mutual funds	75,428,176	-	-	75,428,176
Fixed-income securities	-	21,122,393	-	21,122,393
Cash equivalents	1,175,475	-	-	1,175,475
Benefit plan assets	$ 131,555,738	$ 21,122,393	$	152,678,131
Uncleared cash disbursements from benefits paid				(5,468,253)
Investments measured at net asset value (NAV)				8,380,969
Total benefit plan assets				$ 155,590,847
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Equity mutual funds	$ 46,690,283	$ -	$ -	$ 46,690,283
Fixed-income mutual funds	69,726,689	-	-	69,726,689
Fixed-income securities	-	19,673,412	-	19,673,412
Cash equivalents	1,866,335	-	-	1,866,335
Benefit plan assets	$ 118,283,307	$ 19,673,412	$ -	137,956,719
Uncleared cash disbursements from benefits paid				(3,866,878)
Investments measured at net asset value (NAV)				7,028,808
Total benefit plan assets				$ 141,118,649

Investments that were measured at net asset value (NAV) per share (or its equivalent) as a practical expedient have not been classified in the fair value hierarchy. These investments represent holdings in a single private investment fund that are redeemable at the election of the holder upon no more than 30 days' notice. The values reported above are based on information provided by the fund manager.

Pension Plan and Other Postretirement Benefit Assumptions—Actuarial assumptions used to determine benefit obligations at December 31, 2019 and 2018, were as follows:

	Pension Plan		Other Postretirement Benefits			
	2019	2018	2019		2018	
			Medical	Life	Medical	Life
Discount rate	3.58 %	4.40 %	3.55 %	3.55 %	4.40 %	4.40 %
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Actuarial assumptions used to determine net periodic benefit cost for the years ended December 31, 2019 and 2018, were as follows:

	2019	2018	2019		2018	
			Medical	Life	Medical	Life
Discount rate	4.40 %	3.75 %	4.40 %	4.40 %	3.76 %	3.76 %
Expected long-term return on plan assets	6.00	6.00	5.33	6.00	5.33	6.00
Rate of compensation increase	3.00	3.00	N/A	3.00	N/A	3.00

In selecting the expected long-term rate of return on assets, the Companies considered the average rate of earnings expected on the funds invested to provide for plan benefits. This included considering the Pension Plan and VEBA trusts' asset allocation, and the expected returns likely to be earned over the life of the Pension Plan and the VEBAs.

Assumed health care cost trend rates at December 31, 2019 and 2018, were as follows:

	2019	2018
Health care trend rate assumed for next year—participants under 65	7.00 %	7.00 %
Health care trend rate assumed for next year—participants over 65	7.30	19.40
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants under 65	5.00	5.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)—participants over 65	5.00	5.00
Year that the rate reaches the ultimate trend rate	2024	2024

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service and interest cost	$ 1,274,727	$ (1,043,944)
Effect on postretirement benefit obligation	19,856,817	(16,262,286)

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS AS OF AND FOR THE YEARS ENDED DECEMBER 31, 2019 AND 2018

Pension Plan and Other Postretirement Benefit Assets—The asset allocation for the Pension Plan and VEBA trusts at December 31, 2019 and 2018, by asset category was as follows:

	Pension Plan		VEBA Trusts	
	2019	**2018**	**2019**	**2018**
Asset category:				
Equity securities	31 %	27 %	39 %	37 %
Debt securities	69	73	61	63

Pension Plan and Other Postretirement Benefit Contributions—The Companies expect to contribute $5,800,000 to their Pension Plan and $21,500 to their Other Postretirement Benefits plan in 2020.

Estimated Future Benefit Payments—The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

Years Ending December 31	Pension Plan	Other Postretirement Benefits
2020	$ 9,176,543	$ 6,640,020
2021	9,826,112	7,064,850
2022	10,603,824	7,596,021
2023	11,268,181	8,175,889
2024	12,239,883	8,788,750
Five years thereafter	66,774,987	49,888,077

Postemployment Benefits—The Companies follow the accounting guidance in FASB ASC 712, *Compensation—Non-Retirement Postemployment Benefits*, and accrue the estimated cost of benefits provided to former or inactive employees after employment but before retirement. Such benefits include, but are not limited to, salary continuations, supplemental unemployment, severance, disability (including workers' compensation), job training, counseling, and continuation of benefits, such as health care and life insurance coverage. The cost of such benefits and related obligations has been allocated to OVEC and IKEC in the accompanying consolidated financial statements. The allocated amounts represent approximately a 42% and 58% split between OVEC and IKEC, respectively, as of December 31, 2019, and approximately a 59% and 41% split between OVEC and IKEC, respectively, as of December 31, 2018. The liability is offset with a corresponding regulatory asset and represents unrecognized postemployment benefits billable in the future to customers. The accrued cost of such benefits was $5,201,536 and $4,147,956 at December 31, 2019 and 2018, respectively.

Defined Contribution Plan—The Companies have a trustee-defined contribution supplemental pension and savings plan that includes 401(k) features and is available to employees who have met eligibility requirements. The Companies' contributions to the savings plan equal 100% of the first 1% and 50% of the next 5% of employee-participants' pay contributed. In addition, the Companies provide contributions to eligible employees, hired on or after January 1, 2015, of 3% to 5% of pay based on age and service. Benefits to participating employees are based solely upon amounts contributed to the participants' accounts and investment earnings. By its nature, the plan is fully funded at all times. The employer contributions for 2019 and 2018 were $1,966,847 and $2,014,215, respectively.

9. ENVIRONMENTAL MATTERS

Air Regulations

On March 10, 2005, the United States Environmental Protection Agency (the U.S. EPA) issued the Clean Air Interstate Rule (CAIR) that required significant reductions of SO_2 and NO_x emissions from coal-burning power plants. On March 15, 2005, the U.S. EPA also issued the Clean Air Mercury Rule (CAMR) that required significant mercury emission reductions for coal-burning power plants. These emission reductions were required in two phases: 2009 and 2015 for NO_x, 2010 and 2015 for SO_2, and 2010 and 2018 for mercury. Ohio and Indiana subsequently finalized their respective versions of CAIR and CAMR. In response, the Companies determined that it would be necessary to install flue gas desulfurization (FGD) systems at both plants to comply with these rules. Following completion of the necessary engineering and permitting, construction was started on the FGD systems, and the two Kyger Creek FGD systems were placed into service in 2011 and 2012, while the two Clifty Creek FGD systems were placed into service in 2013.

After the promulgation of CAIR and CAMR, a series of legal challenges to those rules resulted in their replacement with additional rules. CAMR was replaced with a rule referred to as the Mercury and Air Toxics Standards (MATS) rule. The rule became final on April 16, 2012, and the Companies had to demonstrate compliance with MATS emission limits on April 16, 2015. The MATS rule has also undergone legal challenges since it went into effect, and there are a few remaining legal issues pending. The controls the Companies have installed have proven to be adequate to meet the stringent emissions requirements outlined in the MATS rule.

After CAIR was promulgated, legal challenges resulted in that rule being remanded back to the U.S. EPA. The U.S. EPA subsequently promulgated a replacement rule to CAIR called the Cross-State Air Pollution Rule (CSAPR). CSAPR was issued on July 6, 2011, and it was scheduled to go into effect on January 1, 2012. However, a legal challenge of that rule resulted in a stay. The stay was lifted by the D.C. Circuit Court in 2014 and CSAPR, which requires significant NO_x and SO_2 emissions reductions, became effective on January 1, 2015. Further legal challenges of CSAPR resulted in the U.S. Supreme Court remanding portions of the CSAPR rule back to the D.C. Circuit Court for additional review and subsequent action by the U.S. EPA. This resulted in U.S. EPA issuing the CSAPR Update rule which became final on September 7, 2016, and went into effect beginning with the May 1, 2017 to September 30, 2017 ozone season. The CSAPR Update did not replace CSAPR, it only required additional reductions in NO_x emissions from utilities in twenty-two states (including Ohio and Indiana) during the ozone season. The Companies prepared for and implemented a successful compliance strategy for the CSAPR Update rule requirements in the 2017 ozone season. That strategy was standardized

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to meet future ozone season compliance obligations, and its execution provided for another successful ozone season in 2019. The CSAPR Update Rule has also been subject to extensive litigation, and the D.C. Circuit Court of Appeals issued a decision on September 13, 2019, on one of those legal challenges that remanded portions of this rule back to U.S. EPA to address. The EPA has not yet acted on the remand; however, the Companies are not currently anticipating any potential changes in the rule to address the D.C. Circuit Court remand that would materially impact our current compliance strategy or change future operations.

As a result of the installation and effective operation of the FGD systems and the SCR systems at each plant, management did not need to purchase additional annual SO_2 allowances, annual NO_x allowances or ozone season NO_x allowances in 2019 to cover actual emissions. The Companies also maintain a bank of allowances for all three programs as a hedge to cover future emissions in the event of any short-term operating events or other external factors. Depending on a variety of operational and economic factors, management may elect to consume a portion of these banked allowances and/or strategically purchase additional CSAPR annual and ozone season allowances in 2020 and beyond for compliance with the CSAPR and CSAPR Update rules.

With all FGD systems fully operational, the Companies continue to expect to have adequate SO_2 allowances available every year without having to rely on market purchases to comply with the CSAPR rules in their current form. Given the success of the Companies' NO_x ozone season compliance strategy, the purchase of additional NO_x allowances is less likely in the short term as well; however, the Companies did implement changes in unit dispatch criteria for Clifty Creek Unit 6 during the 2017 and subsequent ozone seasons and are continuing to evaluate the need for additional NO_x controls for this unit to provide additional flexibility in operating this unit in the event future NO_x regulations place additional emission constraints on the utility industry.

CCR Rule

In 2010, the U.S. EPA published a proposed rule to regulate the disposal and beneficial reuse of coal combustion residuals (CCRs), including fly ash and boiler slag generated at coal-fired electric generating units as well as FGD gypsum generated at some coal-fired plants. The proposed rule contained two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial reuse and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and existing unlined surface impoundments.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. To comply with a court-ordered deadline, the U.S. EPA issued a prepublication copy of its final rule in December 2014. The rule was published in the Federal Register in April 2015 and became effective in October 2015.

In the final rule, the U.S. EPA elected to regulate CCR as a nonhazardous solid waste and issued new minimum federal solid waste management standards. The rule applies to new and existing active CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes new and additional construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements. The rule is self-implementing and currently does not require state action. As a result of this self-implementing feature, the rule contains extensive recordkeeping, notice, and Internet posting requirements.

The Companies have been systematically implementing the applicable provisions of the CCR rule. The Companies have completed all compliance obligations associated with the rule to date and are continuing to evaluate what, if any, impacts groundwater quality will have on the South Fly Ash Pond and landfill at Kyger Creek and the West Boiler Slag Pond and landfill at Clifty Creek. To date, these four CCR units continue to meet the groundwater monitoring standards of the CCR Rule. The Companies have been evaluating potential impacts to groundwater quality near the boiler slag pond at Kyger Creek and the landfill runoff collection pond at Clifty Creek as required by the CCR Rule. The Companies have determined that statistically significant increases (SSIs) in certain groundwater parameters are present at the two identified locations, and additional steps as defined by the CCR rule were taken. The evaluation of whether an SSI exists is a required component of the groundwater monitoring conditions of the CCR rule. A determination that an SSI appears to be present requires additional evaluation to be undertaken by the facility to determine if there are alternative sources that are influencing groundwater quality and to evaluate the extent of the groundwater quality impact. Concurrently, a facility must continue to evaluate groundwater quality as required by the CCR rule, and determine what potential corrective actions are feasible to address the SSIs. The Companies conducted Alternative Source Demonstrations (ASD) to determine if groundwater was being influenced from sources other than the CCR unit. The ASDs were unable to definitively prove that alternative sources were directly influencing groundwater quality. As a result, the Companies worked with their Qualified Professional Engineer (QPE) to determine what corrective actions were feasible for each CCR unit, and then held a public meeting to discuss these options with the public prior to selecting a remedy. The Companies continue to work through the compliance requirements of the CCR Rule and remain in compliance.

Since the initial rollout of the CCR rules in 2015, several legal, legislative and regulatory events impacting the scope, applicability and future CCR compliance obligations and timelines have also taken place. Final actions include federal legislation (i.e., the WIIN Act) that provides a pathway for states to seek approval for administering and enforcing the federal CCR program, U.S. EPA’s issuance of a Phase I, Part I revision to the CCR rules on March 1, 2018, and the D.C. Circuit Court’s August 21, 2018, ruling vacating and remanding portions of the CCR rule. In addition, the U.S. EPA announced plans to issue additional revisions to the CCR rule, some of which would also directly address the D.C. Circuit Court’s issues raised in its August 21, 2018, decision. Other proposed revisions to the 2015 CCR rules that the U.S. EPA is currently undertaking will address outstanding issues previously identified by the agency and the Court. Two draft CCR rules entitled Part A and Part B, are in the public notice phase and are expected to be issued in final form later in 2020. Part A proposes a significant revision to the 2015 CCR rule requiring all impoundments that do not meet the liner requirements outlined in the 2015 CCR rule to cease receiving CCR material and initiate closure by August 31, 2020, regardless of their overall compliance status. If that date is not technically feasible, an alternate date to cease receiving CCR material and initiate closure can be secured from U.S. EPA through a proposed extension request process. The surface impoundments at Kyger Creek and Clifty Creek do not meet the liner design requirements required under the 2015 CCR rule. As a result, the Companies have begun an engineering evaluation to determine a technically feasible timeline for discontinuing placement of CCR materials in these impoundments and the initiation of closure consistent with the draft rule. Subsequently, the Companies intend to submit a technical justification document to U.S. EPA that demonstrates why additional time is needed to cease placement of CCR in the surface impoundments and initiate closure. The Companies anticipate U.S. EPA will approve the alternative schedule at this time. Separately, the proposed Part B revisions to the 2015 CCR rule outline the development of a federal permitting program to regulate and enforce the CCR rule at all applicable facilities consistent with the Congressional mandate outlined in the WIIN Act. This federal permit program would replace the current enforcement mechanism of a self-implementing rule enforced through citizen suits and place it back with U.S. EPA or any state regulatory that receives primacy to implement the CCR permitting within their respective state. The Companies are actively monitoring these developments and adapting their CCR compliance program to ensure compliance obligations and timelines are adjusted accordingly. Changes in regulations or in the Companies' strategies for mitigating the impact of coal combustion residuals could potentially result in material increases to the asset retirement obligations.

In February 2014, the U.S. EPA completed a risk evaluation of the beneficial uses of coal fly ash in concrete and FGD gypsum in wallboard and concluded that the U.S. EPA supports these beneficial uses. Currently, approximately 60 percent of the coal ash and other residual products from our generating facilities are reused in the production of cement and wallboard, as soil amendments, as abrasives or road treatment materials, and for other beneficial uses.

NAAQS Compliance for SO_2

On June 22, 2010, the U.S. EPA revised the Clean Air Act by developing and publishing a new one-hour SO_2 NAAQS of 75 parts per billion, which replaced the previously existing 24-hour and annual standards, and became effective on August 23, 2010. States with areas failing to meet the standard were required to develop state implemented plans to expeditiously attain and maintain the standard.

On August 15, 2013, the U.S. EPA published its initial non-attainment area designations for the new one-hour SO_2, which did not include the areas around Kyger Creek or Clifty Creek. However, the amended rule does establish that at a minimum, sources that emit 2,000 tons SO_2 or more per year be characterized by their respective states using either modeling of actual source emissions or through appropriately sited ambient air quality monitors.

In addition, U.S. EPA entered into a settle agreement with Sierra Club/NRDC in the U.S. District Court for the Northern District of California requiring U.S. EPA to take certain actions, including completing area designation by July 2, 2016, for areas with either monitored violations based on 2013-15 air quality monitoring or sources not announced for retirement that emitted more than 16,000 tons SO_2 or more than 2,600 tons with a 0.45 SO_2/mmBtu emission rate in 2012.

Both Kyger Creek and Clifty Creek directly or indirectly triggered one of the criteria and have been evaluated by the respective state regulatory agencies through modeling. The modeling results showed Clifty Creek could meet the new one-hour SO_2 limit using their current scrubber systems without any additional investment or modifications. Kyger Creek's modeling data was rejected by U.S. EPA as inconclusive in 2016. As a result, U.S. EPA required Kyger Creek install an SO_2 monitoring network around the plant and monitor ambient air quality beginning on January 1, 2017. Based on the first three years of data from that network, Ohio EPA will be preparing an updated petition to U.S. EPA requesting that the area in the county surrounding the plant be designated in attainment of the one-hour standard. Finally, on February 26, 2019, the U.S. EPA issued a final decision that it is retaining the existing primary SO_2 NAAQS at 75 parts per billion for the next five-year NAAQS review cycle. Given this decision, combined with current scrubber performance, the Companies expect to avoid more restrictive permit limits relative to its SO_2 emissions or the need for additional capital investment in major scrubber upgrades or modifications.

Steam Electric ELGs

On September 30, 2015, the U.S. EPA signed a new final rule governing Effluent Limitations Guidelines (ELGs) for the wastewater discharges from steam electric power generating plants. The rule, which was formally published in the Federal Register on November 3, 2015, impacted future wastewater discharges from both the Kyger Creek and Clifty Creek Stations.

The rule was intended to require the Companies to modify the way they handle a number of wastewater processes at both power plants. Specifically, the new ELG standards were going to affect the following wastewater processes in three ways listed below; however, in April 2017, the U.S. EPA issued an administrative stay on the ELG rule; and then in June 2017, the U.S. EPA issued a separate rulemaking staying the compliance deadlines for portions of the ELG rule applicable to bottom ash sluice water and to FGD wastewater discharges. The U.S. EPA has been working to revise the rule to evaluate what constitutes "best available technology" for these two wastewater discharges and issue an updated rule by no later than the fall of 2020. While the revised rule is not yet final, the Companies' understanding of what the original impacts and updated impacts to each wastewater discharge are highlighted below:

1. Kyger Creek will need to convert to dry fly ash handling by no later than December 31, 2023. The U.S. EPA stay on portions of the ELG rule does not impact the need to convert Kyger Creek Station to dry fly ash handling or the associated timeline. The Clifty Creek Station already has a dry fly ash handling system in place, so this provision of the rule will not impact Clifty Creek's operations.

2. The new ELG rules originally prohibited the discharge of bottom ash sluice water from boiler slag/bottom ash wastewater treatment systems. For Clifty Creek and Kyger Creek, this will likely result in the conversion of each plant's boiler slag pond to a closed-loop sluicing system for boiler slag. The Companies conducted a Phase I engineering study in 2016 to determine options and costs associated with retrofitting the plants' boiler slag treatment systems but postponed the study until more information was available from U.S. EPA on the technologies being considered in the revised rule. After reviewing the new draft rule, the Companies resumed the engineering study needed to formulate an

overall compliance strategy based on this updated information. This study includes a further evaluation of technologies or retrofits capable of complying with the requirements of the revised rule, which include preliminary engineering, design, and schedule development that were initiated late in 2019. The results of that evaluation are expected to be available in the second quarter of 2020.

3. The new ELG rules originally established new internal limitations for the FGD system wastewater discharges. Specifically, there were to be new internal limits for arsenic, mercury, selenium, and nitrate/nitrite nitrogen from the FGD chlorides purge stream wastewater treatment plant at each plant. For both Clifty Creek and Kyger Creek Stations, the Companies were expecting to be able to meet the mercury and arsenic limitations with the current wastewater treatment technology; however, the Companies were expecting to add some form of biological (or equivalent non-biological) treatment system on the back end of each Station's existing FGD wastewater treatment plant to meet the new nitrate/nitrite nitrogen and selenium limitations. Installation of new controls to meet the final effluent limitations contained in the revised rule are currently on hold while the Companies await further regulatory action from the U.S. EPA that will determine what the new limits for each of these constituents will be in the final ELG rule, which is expected late fall 2020. Once those final effluent limits are established, the Companies will resume evaluation of the appropriate technology, design, and schedule to achieve compliance with the new requirements. Based on the Companies' review of the draft revised ELG rule, the compliance deadline for FGD wastewater has been moved to compliance with the updated requirements no later than December 31, 2025.

Any new ELG limits will be implemented through each Station's wastewater discharge permit, which is typically renewed on a five-year basis. The final compliance dates are expected to be facility-specific and negotiated with the Companies' state permit agencies based on the time needed to plan, secure funding, design, procure, and install necessary control technologies once the new rulemaking has been completed. The Companies will continue to monitor EPA regulatory actions on this rule and will respond as necessary.

316(b) Compliance

The 316(b) rule was published as a final rule in the Federal Register on August 15, 2014, and impacts facilities that use cooling water intake structures designed to withdraw at least 2 million gallons per day from waters of the U.S., and those facilities who also have an NPDES permit. The rule requires such facilities choose one of seven options specified by the rule to reduce impingement to fish and other aquatic organisms. Additionally, facilities that withdraw 125 million gallons or more per day must conduct entrainment studies to assist state permitting authorities in determining what site-specific controls are required to reduce the number of aquatic organisms entrained by each respective cooling water system.

The Companies have completed the required two-year fish entrainment studies and filed the reports with the respective state regulatory agencies consistent with regulatory requirements under 40 CFR Section 122.21(r).

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The timeline for determining if retrofits may be required to the cooling water systems at either Clifty Creek or Kyger Creek, as well as the type of retrofit required, will be negotiated with each state regulatory agency during future NPDES Permit renewals consistent with state regulatory obligations under 40 CFR Section 125.98(f).

The environmental rules and regulations discussed throughout the Environmental Matters footnote could require additional capital expenditures or maintenance expenses in future periods.

10. FAIR VALUE MEASUREMENTS

The accounting guidance for Financial Instruments requires disclosure of the fair value of certain financial instruments. The estimates of fair value under this guidance require the application of broad assumptions and estimates. Accordingly, any actual exchange of such financial instruments could occur at values significantly different from the amounts disclosed.

OVEC utilizes its trustee’s external pricing service in its estimate of the fair value of the underlying investments held in the benefit plan trusts and investment portfolios. The Companies’ management reviews and validates the prices utilized by the trustee to determine fair value. Equities and fixed-income securities are classified as Level 1 holdings if they are actively traded on exchanges. In addition, mutual funds are classified as Level 1 holdings because they are actively traded at quoted market prices. Certain fixed-income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed-income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed-income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, bids, offers, and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments.

As of December 31, 2019 and 2018, the Companies held certain assets that are required to be measured at fair value on a recurring basis. These consist of investments recorded within long-term investments. The investments consist of money market mutual funds, equity mutual funds, and fixed-income municipal securities. Changes in the observed trading prices and liquidity of money market funds are monitored as additional support for determining fair value, and unrealized gains and losses are recorded in earnings.

The methods described above may produce a fair value calculation that may not be indicative of net realizable value or reflective of future fair values. Furthermore, while the Companies believe their valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

As cash and cash equivalents, current receivables, current payables, and line of credit borrowings are all short-term in nature, their carrying amounts approximate fair value.

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Long-Term Investments—Assets measured at fair value on a recurring basis at December 31, 2019 and 2018, were as follows:

	Fair Value Measurements at Reporting Date Using		
2019	**Quoted Prices in Active Market for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Equity mutual funds	$ 99,982,734	$ -	$ -
Fixed-income mutual funds	37,002,850	-	-
Fixed-income municipal securities		101,374,099	-
Cash equivalents	2,379,596	-	-
Total fair value	$139,365,180	$101,374,099	$ -
2018	**(Level 1)**	**(Level 2)**	**(Level 3)**
Equity mutual funds	$ 64,095,224	$ -	$ -
Fixed-income mutual funds	22,186,437	-	-
Fixed-income municipal securities	-	93,085,183	-
Cash equivalents	1,904,689	-	-
Total fair value	$ 88,186,350	$ 93,085,183	$ -

Long-Term Debt—The fair values of the senior notes and fixed-rate bonds were estimated using discounted cash flow analyses based on current incremental borrowing rates for similar types of borrowing arrangements. These fair values are not reflected in the balance sheets. The fair values and recorded values of the senior notes and fixed- and variable-rate bonds as of December 31, 2019 and 2018, are as follows:

	2019		2018	
	Fair Value	**Recorded Value**	**Fair Value**	**Recorded Value**
Total	1,390,779,759	1,275,148,664	1,398,244,690	1,329,819,085

11. LEASES

OVEC has various operating leases for the use of other property and equipment.

On January 1, 2019, the Companies adopted ASC 842, "Leases" which, among other changes, requires the Companies to record liabilities classified as operating leases on the balance sheet

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along with a corresponding right-of-use asset. Results for reporting periods beginning January 1, 2019, are presented under Topic 842, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting under Topic 840. The Companies elected the package of practical expedients available for expired or existing contracts, which allowed them to carryforward their historical assessments of whether contracts are or contain leases, lease classification tests and treatment of initial direct costs. Further, the Companies elected to not separate lease components from non-lease components for all fixed payments, and excluded variable lease payments in the measurement of right-of-use assets and lease obligations.

Upon adoption of ASC 842, the impact was a $22,000 increase in ROU assets and operating lease obligations. These adjustments are the result of assigning a right-of-use asset and related lease liability to the Companies operating leases. There were no cumulative effect adjustments to opening retained earnings, and adoption of the lease standard had no impact to cash from or used in operating, financing, or investing activities on the cash flow statement.

The Companies determine whether an arrangement is, or includes, a lease at contract inception. Leases with an initial term of 12 months or less are not recognized on the balance sheet. The Companies recognize lease expense for these leases on a straight-line basis over the lease term.

Operating lease right-of-use assets and liabilities are recognized at commencement date and initially measured based on the present value of lease payments over the defined lease term.

The leases typically do not provide an implicit rate; therefore, the Companies use the estimated incremental borrowing rate at the time of lease commencement to discount the present value of lease payments. In order to apply the incremental borrowing rate, a portfolio approach with a collateralized rate is utilized. Assets were grouped based on similar lease terms and economic environments in a manner whereby the Companies reasonably expect that the application is not expected to differ materially from a lease-by-lease approach.

The Companies have operating and finance leases for the use of vehicles, property, and equipment. The leases have remaining terms of 1 year to 7 years. The components of lease expense were as follows:

Year Ending December 31,	**2019**
Operating lease cost	$ 15,095
Finance lease cost:	
Amortization of leased assets	$ 258,411
Interest on lease liabilities	61,547
Total finance lease cost	$ 319,958

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Supplemental cash flow information related to leases was as follows:

Operating cash flows from operating leases	$15,095
Operating cash from finance leases	55,793
Financing cash flows from finance leases	156,130
Weighted average remaining lease term:	
Operating leases	< 1 year
Finance leases	4 years
Weighted average discount rate:	
Operating leases	3.8 %
Finance leases	8.1 %

The amount of operating lease ROU assets and liabilities is $7,431 and $0 as of December 31, 2019 and 2018, respectively.

The amount in property under finance leases is $1,545,051 and $1,156,718 with accumulated depreciation of $669,164 and $464,194 as of December 31, 2019 and 2018, respectively.

Future cash flows of operating leases, and maturities of financing lease liabilities are as follows:

Years Ending December 31	Operating	Finance
2020	$ 7,512	$291,782
2021	-	221,997
2022	-	151,065
2023	-	89,223
2024	-	55,121
Thereafter	-	105,649
Total future minimum lease payments	$ 7,512	914,837
Less estimated interest element		168,135
Estimated present value of future minimum lease payments		$746,702

12. COMMITMENTS AND CONTINGENCIES

The Companies are party to or may be affected by various matters under litigation. Management believes that the ultimate outcome of these matters will not have a significant adverse effect on either the Companies' future results of operation or financial position.

On March 31, 2018, FirstEnergy Solutions Corp. (FES), one of the Sponsoring Companies under the ICPA, filed for Chapter 11 bankruptcy protection under the United States Bankruptcy Code in the United States Bankruptcy Court for the Northern District of Ohio (the "Bankruptcy Court"). OVEC made a preemptive filing on March 26, 2018, at the Federal Energy Regulatory Commission (FERC) requesting either (i) an order finding that FES's anticipated rejection of the ICPA would constitute a violation of that agreement's terms and would not satisfy the Federal Power Act's "public interest" standard, or, (ii) an order declaring that FERC has exclusive jurisdiction over the proposed rejection of the ICPA (the "FERC Action"). On April 1, 2018, FES filed in the Bankruptcy Court a motion to reject the ICPA and separately obtained an order temporarily enjoining the FERC Action. On May 11, 2018, the Bankruptcy Court granted a preliminary injunction enjoining FERC from reviewing FES's requested rejection of the ICPA under the public interest standard. FERC subsequently filed an appeal of this decision with the United States Court of Appeals for the Sixth Circuit (the "Injunction Appeal"), which OVEC joined as an intervenor. On July 31, 2018, the Bankruptcy Court granted FES's motion to reject the ICPA using the "business judgement" standard used to evaluate contract rejection under the Bankruptcy Code (the "Rejection Order"). Per the ICPA, upon rejection, OVEC made available to all other Sponsoring Companies FES's entitlement to available energy under the ICPA. OVEC appealed the Rejection Order to the Sixth Circuit (the "Rejection Appeal"). The Rejection Appeal was ultimately consolidated with the Injunction Appeal (together as consolidated, the "Sixth Circuit Rejection Appeal"). On December 12, 2019, the U.S. Court of Appeals for Sixth Circuit ruled on the Sixth Circuit Rejection Appeal by (1) affirming the Bankruptcy Court's jurisdiction over the rejection of the ICPA and (2) finding that the Bankruptcy Court should have considered the public interest in the standard for rejection and remanding to the Bankruptcy Court for further consideration under a heightened standard, after giving FERC a reasonable opportunity to weigh in. OVEC filed a petition for rehearing "en banc," and on March 13, 2020, the Sixth Circuit denied the petition.

On July 31, 2019, OVEC and FES entered into a stipulation with respect to OVEC's objection to confirmation of the FES plan of reorganization, stipulating that FES (a) would not seek to dismiss OVEC's Sixth Circuit appeal, or, if applicable, OVEC's appeal of an order with respect to an objection by OVEC to confirmation of the plan arising under section 1129(a)(6) of the Bankruptcy Code or oppose further review by the United States Supreme Court, on the grounds of mootness. OVEC objected to confirmation of the FES plan under section 1129(a)(6) of the Bankruptcy Code, which requires any governmental regulatory commission with jurisdiction, after confirmation of the plan, over the rates of a debtor to approve any rate change provided for in the plan, or that such rate change is expressly conditioned on such regulatory approval. OVEC's objection was overruled at the confirmation hearing on August 20th and 21st. The FES plan of reorganization was confirmed on October 16, 2019. On October 29, 2019, OVEC moved to certify a direct appeal of the Bankruptcy Court's confirmation order to the Sixth Circuit. On November 27, 2019, the Bankruptcy Court granted OVEC's motion to certify the confirmation order for direct appeal to the Sixth Circuit. On March 24, 2020, the Sixth Circuit granted OVEC's petition for direct appeal of the confirmation order.

On October 14, 2018, OVEC filed with the Bankruptcy Court its rejection damages claim of approximately $540 million against FES. The amount of OVEC's rejection damages claim has not been litigated at this time. Until the outcome of the Sixth Circuit Appeal and, potentially, a subsequent proceeding at FERC, it is undetermined whether FES will ultimately be permitted to reject its interest in the ICPA. FES's share of obligations, in each case under the ICPA, is approximately 5%. However, the Companies currently have access to the credit markets to fund ongoing liquidity needs, and the Sponsoring Companies remain obligated to fund debt service payments when due. The Companies accounts receivables as of December 31, 2019, on the consolidated balance sheets include receivables for FES's share of the Sponsor billings from March 2018 through December 31, 2019, which amounts to $38.5 million at December 31, 2019.

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OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of Ohio Valley Electric Corporation

We have audited the accompanying consolidated financial statements of Ohio Valley Electric Corporation and its subsidiary company, Indiana-Kentucky Electric Corporation (the "Companies"), which comprise the consolidated balance sheets as of December 31, 2019 and 2018, and the related consolidated statements of income and retained earnings and cash flows for the years then ended, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Companies' preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Companies' internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Companies as of December 31, 2019 and 2018, and the results of their operations and their cash flows for the years then ended in accordance with accounting principles generally accepted in the United States of America.

/s/Deloitte & Touche LLP
Columbus, Ohio
April 17, 2020

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

OVEC PERFORMANCE – A 5-YEAR COMPARISON

	2019	2018	2017	2016	2015
Net Generation (MWh)	**11,238,298**	12,146,884	11,940,259	9,946,877	8,899,619
Energy Delivered (MWh) to:					
DOE	**125,881**	148,613	156,768	173,873	221,610
Sponsors	**11,234,353**	11,863,505	11,724,662	9,745,956	8,681,829
Maximum Scheduled (MW) by:					
DOE	**21**	33	34	35	40
Sponsors	**2,209**	2,173	2,186	2,167	2,047
Power Costs to:					
DOE	**$4,641,000**	$7,606,000	$8,188,000	$8,519,000	$10,249,000
Sponsors	**$640,801,000**	$644,114,000	$636,287,000	$571,687,000	$559,123,000
Average Price (MWh):					
DOE	**$36.869**	$51.180	$52.229	$48.996	$46.248
Sponsors	**$57.040**	$54.294	$54.270	$58.657	$64.402
Operating Revenues	**$614,667,000**	$615,839,000	$624,058,000	$585,896,000	$565,329,000
Operating Expenses	**$554,642,000**	$523,196,000	$560,170,000	$515,702,000	$492,803,000
Cost of Fuel Consumed	**$274,843,000**	$277,369,000	$288,503,000	$261,833,000	$246,582,000
Income and Other Taxes	**$8,418,000**	$12,165,000	$11,975,000	$12,329,000	$11,646,000
Payroll	**$55,491,000**	$57,569,000	$58,847,000	$60,051,000	$63,909,000
Fuel Burned (tons)	**5,111,144**	5,428,783	5,338,318	4,603,575	4,134,871
Heat Rate (Btu per kWh, net generation)	**10,714**	10,540	10,622	10,904	10,681
Unit Cost of Fuel Burned (per mmBtu)	**$2.28**	$2.17	$2.27	$2.41	$2.59
Equivalent Availability (percent)	**78.2**	76.6	75.6	72.9	64.7
Power Use Factor (percent)	**76.23**	84.19	83.90	72.67	73.07
Employees (year-end)	**591**	640	666	708	738

OHIO VALLEY ELECTRIC CORPORATION AND SUBSIDIARY COMPANY

DIRECTORS

Ohio Valley Electric Corporation

[1] **THOMAS ALBAN**, Columbus, Ohio
Vice President, Power Generation
Buckeye Power, Inc.

DAN ARBOUGH, Louisville, Kentucky
Treasurer
LG&E and KU Energy LLC

ERIC D. BAKER, Cadillac, Michigan
President and Chief Executive Officer
Wolverine Power Supply Cooperative, Inc.

[1] **CHRISTIAN T. BEAM**, Charleston, West Virginia
President and Chief Operating Officer
Appalachian Power

[1,2] **LONNIE E. BELLAR,** Louisville, Kentucky
Chief Operating Officer
LG&E and KU Energy LLC

[2] **PAUL CHODAK III**, Columbus, Ohio
Executive Vice President - Generation
American Electric Power Company, Inc.

WAYNE D. GAMES, Evansville, Indiana
Vice President – Power Supply
Vectren Corporation

[1] **LANA L. HILLEBRAND**, Columbus, Ohio
Senior Vice President and Chief Administrative Officer
American Electric Power Company, Inc.

MARK E. MILLER, Indianapolis, Indiana
Chief Operating Officer
Indianapolis Power & Light Company

STEVEN K. NELSON, Coshocton, Ohio
Chairman, Buckeye Power Board of Trustees
The Frontier Power Company

[2] **PATRICK W. O'LOUGHLIN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power, Inc.

[2] **DAVID W. PINTER**, Akron, Ohio
Executive Director, Business Development
FirstEnergy Corp.

[2] **RAJA SUNDARARAJAN**, Gahanna, Ohio
President and Chief Operating Officer, AEP Ohio
American Electric Power Company, Inc.

[2] **JOHN A. VERDERAME**, Charlotte, North Carolina
Director, Power Trading & Dispatch
Duke Energy Corporation

Indiana-Kentucky Electric Corporation

[2] **PAUL CHODAK III**, Columbus, Ohio
Executive Vice President - Generation
American Electric Power Company, Inc.

WAYNE D. GAMES, Evansville, Indiana
Vice President – Power Supply
Vectren Corporation

MARC E. LEWIS, Fort Wayne, Indiana
Vice President, External Relations
Indiana Michigan Power

DAVID A. LUCAS, Fort Wayne, Indiana
Vice President – Finance
Indiana Michigan Power

[2] **PATRICK W. O'LOUGHLIN**, Columbus, Ohio
President and Chief Executive Officer
Buckeye Power, Inc.

[2] **DAVID W. PINTER**, Akron, Ohio
Executive Director, Business Development
FirstEnergy Corp.

TOBY L. THOMAS, Fort Wayne, Indiana
President and Chief Operating Officer
Indiana Michigan Power

OFFICERS—OVEC AND IKEC

PAUL CHODAK III
President

ROBERT A. OSBORNE
Vice President and
Chief Operating Officer

JUSTIN J. COOPER
Chief Financial Officer,
Secretary and Treasurer

KASSANDRA K. MARTIN
Assistant Secretary, Treasury Manager

JULIE SLOAT
Assistant Secretary and
Assistant Treasurer

[1]Member of Human Resources Committee.
[2]Member of Executive Committee.

Indiana Michigan Power Company
OVEC Billing Data
Calendar Year 2020

	MWh	Energy Charge	Demand Charge	Transmission Charge	PJM Expenses/Fees	Total Bill
Jan 2020	73,111	$1,774,282	$2,002,353	$103,859	$31,144	$3,911,638
Feb	64,814	$1,642,742	$1,939,210	$100,820	$33,116	$3,715,888
Mar	53,273	$1,423,887	$2,466,473	$96,633	$26,062	$4,013,055
Apr	30,105	$974,603	$2,635,093	$87,568	$28,325	$3,725,589
May	33,978	$978,732	$2,386,859	$88,915	-$251,480	$3,203,026
Jun	65,730	$1,609,964	$1,938,162	$102,441	$7,588	$3,658,155
Jul	73,949	$1,837,940	$2,150,072	$105,719	$10,518	$4,104,250
Aug	70,557	$1,715,507	$2,197,338	$104,073	-$1,852	$4,015,065
Sep	52,291	$1,396,224	$2,308,890	$96,881	$10,427	$3,812,422
Oct	45,990	$1,224,347	$2,547,592	$94,374	$13,366	$3,879,678
Nov	68,609	$1,712,394	$2,267,110	$103,728	$1,371	$4,084,602
Dec	89,069	$2,197,204	$3,231,200	$111,049	$2,250	$5,541,702

Indiana Michigan Power Company
As reported by PJM
AG 3-44 Attachment 1

	Energy Revenues	Ancillary Revenue
Jan 2020	$1,657,028.64	$857.38
Feb 2020	$1,321,633.07	$720.01
Mar 2020	$968,761.98	$914.27
Apr 2020	$501,605.04	$153.25
May 2020	$635,743.61	$419.63
Jun 2020	$1,327,334.66	$3,762.91
Jul 2020	$1,911,109.59	$4,155.59
Aug 2020	$1,596,450.88	$4,539.38
Sep 2020	$1,108,804.20	$2,797.40
Oct 2020	$1,181,275.64	$10,272.84
Nov 2020	$1,471,473.69	$8,170.18
Dec 2020	$2,234,765.91	7,900.73

Indiana Michigan Power Company
Analysis of Monthly Ohio Valley Electric Corporation (OVEC) Net Energy Revenues for 2020

	OVEC Energy Charge	OVEC Energy Revenues	Net Energy Revenues
	(b)	**(a)**	= (b) - (a)
Jan 2020	$1,774,282	$1,657,028.64	-$117,253.18
Feb 2020	$1,642,742	$1,321,633.07	-$321,108.63
Mar 2020	$1,423,887	$968,761.98	-$455,125.07
Apr 2020	$974,603	$501,605.04	-$472,998.16
May 2020	$978,732	$635,743.61	-$342,988.59
Jun 2020	$1,609,964	$1,327,334.66	-$282,629.00
Jul 2020	$1,837,940	$1,911,109.59	$73,169.26
Aug 2020	$1,715,507	$1,596,450.88	-$119,056.05
Sep 2020	$1,396,224	$1,108,804.20	-$287,419.95
Oct 2020	$1,224,347	$1,181,275.64	-$43,071.53
Nov 2020	$1,712,394	$1,471,473.69	-$240,920.41
Dec 2020	$2,197,204	$2,234,765.91	$37,562.18

Indiana Michigan Power Company
Case No. U-20804
Sierra Club 4th Set, Q7, Attachment 1

Forecasted ICAP
for Portion of Power Purchased by I&M from OVEC
(MW)

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
OVEC	171.7	171.7	171.7	171.7	169.7	167.7	165.8	165.8	167.7	169.7	171.7	171.7

Indiana Michigan Power Company
Case No. U-20804
Sierra Club 4th Set, Q7, Attachment 1

Forecasted ICAP
for Portion of Power Purchased by I&M from AEG
(MW)

Unit	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	462
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	455

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22
Rockport 1	462	462	462	462	462	460	460	460	462	462	462	660
Rockport 2	455	455	455	455	455	455	455	455	455	455	455	na

	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-24	Feb-24	Mar-24	Apr-24	May-24	Jun-24	Jul-24	Aug-24	Sep-24	Oct-24	Nov-24	Dec-24
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

	Jan-25	Feb-25	Mar-25	Apr-25	May-25	Jun-25	Jul-25	Aug-25	Sep-25	Oct-25	Nov-25	Dec-25
Rockport 1	660	660	660	660	660	658	658	658	660	660	660	660
Rockport 2	na	na	na	na	na	na	na	na	na	na	na	na

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-06-AG

Request

Produce any comparisons or other evaluations of the amounts or prices paid for energy and capacity from OVEC in 2020 to market prices or any other benchmarks

Response

The Company values the capacity provided by OVEC under the ICPA as a long-term resource to meet its load obligation per the requirements established in PJM Manual 18. The Company has provided a comparison of energy provided by OVEC to market prices in its response to AG 1-7.

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-08-AG

Request

Describe in detail how I&M value(d) the capacity provided by OVEC in 2020, including any estimates and calculations

Response

Please see the Company's response to AG 1-06.

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-12-AG

Request

Produce any and all Requests for Proposals or other solicitations that I&M or AEPSC have issued for energy, capacity, or both within the past 3 years and through the date of your response.

Response

I&M objects to this request on the grounds that it seeks information that is outside the scope of the PSCR and therefore not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M states the request seeks information from entities that are not parties to this case or subject to the MPSC's jurisdiction, in particular AEPSC. In addition, the request seeks information outside the PSCR review period, (i.e. the past 3 years). I&M further states that it did not issue any RFP's for energy, capacity, or both that would have been in-effect during 2020 and therefore, have no impact on the prudency of I&M's 2020 PSCR costs.

Subject to and without waiving these objections, please see the following documents:

- AG 1-12 IM_Wind_Solar_RFP_110520_Final_PPA.pdf
- AG 1 Zach-I have identified you as the preparer-12 IM_Wind_Solar_RFP_113020_Final_PSA_1.0.pdf

As to objection
Counsel

Preparer
Yetzer

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-13-AG

Request

Produce any and all unsolicited offers that I&M or AEPSC have received for energy, capacity, or both within the past 3 years and through the date of your response.

Response

I&M objects to this request on the grounds that it seeks information that is outside the scope of the PSCR and therefore not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M states the request seeks information from entities that are not parties to this case or subject to the MPSC's jurisdiction, in particular AEPSC. In addition, the request seeks information outside the PSCR review period, (i.e. the past 3 years). I&M further objects to the extent this request seeks information that is confidential, proprietary, competitively sensitive, and/or is a trade secret. Subject to and without waiving these objections, I&M states unsolicited offers were received in the later half of 2020, however, none were for projects that would have had commercial operations during the 2020 PSCR reconciliation period.

As to objection
Counsel

Preparer
Yetzer

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

DATA REQUEST NO. 1-13-AG

Request

Produce any and all unsolicited offers that I&M or AEPSC have received for energy, capacity, or both within the past 3 years and through the date of your response.

Response

I&M objects to this request on the grounds that it seeks information that is outside the scope of the PSCR and therefore not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M states the request seeks information from entities that are not parties to this case or subject to the MPSC's jurisdiction, in particular AEPSC. In addition, the request seeks information outside the PSCR review period, (i.e. the past 3 years). I&M further objects to the extent this request seeks information that is confidential, proprietary, competitively sensitive, and/or is a trade secret. Subject to and without waiving these objections, I&M states unsolicited offers were received in the later half of 2020, however, none were for projects that would have had commercial operations during the 2020 PSCR reconciliation period.

SUPPLEMENTAL RESPONSE

In 2020, Q2/Q3, AEP conducted general market research and reached out to various developers inquiring about projects in development by them in the states of Indiana and Michigan. A couple developers responded with confidential information provided to AEP under the terms of a Non-Disclosure Agreement for projects with a COD of 2022 and 2023. No projects were provided with a 2020 in-service date. No records were retained.

As to objection
Counsel

Preparer
Yetzer

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-14-AG

Request

Identify any and all capacity purchases made by I&M or AEPSC, by any means, within the past 3 years and through the date of your response.

Response

I&M objects to this request on the grounds that it seeks information that is overly broad and not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, I&M states the request seeks information from entities that are not parties to this case or subject to the MPSC's jurisdiction, in particular AEPSC, which may make capacity purchases for several entities. Subject to and without waiving this objection, I&M states no such purchases have been made for I&M.

As to objection
Counsel

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-15-AG

Request

Identify and produce any and all valuations that I&M or AEPSC undertook for FRR capacity in 2020 or in 2021 to date.

Response

I&M has no such valuation.

Preparer
Fee

DTE Energy

1-18-2021

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland:

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	12-31-2020	Actual	
Construction and Retirement Work In Progress		$ 653,951.45	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ 222,482.90	1540-0000-000-03
Fuel Consumption Expense		$ 2,076,641.80	See attached page
Plant Operating Expenses		$ 1,434,882.98	See attached page
Total Actual Expenses		$ 4,387,959.13	
Total Amount Due Detroit Edison		$ 4,387,959.13	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
12-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 229,424.29	$ 42,695.86	5000-0000-002-03
501*	Fuel	$ 798,869.13	$ 148,669.55	5011-0000-002-03
502	Steam Expenses	$ 262,451.24	$ 48,842.18	5020-0000-002-03
505	Electric Expenses	$ 190,074.00	$ 35,372.77	5050-0000-002-03
506	Misc Steam Power Expenses	$ 1,212,367.24	$ 225,621.54	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 244,312.54	$ 45,466.56	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 2,335,176.86	$ 434,576.41	5120-0000-002-03
513	Maintenance - Elect Plant	$ 346,680.90	$ 64,517.32	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 596,643.80	$ 111,035.41	5140-0000-002-03
926	Pensions and Benefits	$ 327,000.00	$ 60,854.70	9260-0000-002-03
Total Direct Production O & M		$ 6,543,000.00	$ 1,217,652.30	

Support Services Costs: **

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI index of 2.5% as ceiling for Monthly Support Service Costs
* Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 1,300,265

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ (15,000.00)	5.1297%	18.61%	$ (2,792)	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ 1,308,974

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
12-31-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax **(billed annually as part of April actual expenses)**

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
12-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	3,513,978.76	653,951.45	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	3,513,978.76	653,951.45	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month	
154 - 101540	Plant materials and operating supplies	18,623,092.72	17,427,590.88	$ 1,195,501.84	
	(see note on previous page regarding M&S)				
	MPPA's Entitlement			18.61%	
	MPPA's Share - Plant Improvements			$ 222,482.90	1540-0000-000-03

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
12-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		653,951.45		653,951.45	
A	Materials and Supplies (see note below)		222,482.90	0.00	222,482.90	
	Total Plant Capital Expenses		$ 876,434.35	$ -	$ 876,434.35	
Plant Operating Expenses						
I	Production O & M Expense		1,300,265		1,300,265	
I	Payroll, Sales & Use Taxes		(2,792)		(2,792)	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			1,308,974		1,308,974	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		1,434,883		1,434,882.98	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	49,360		49,360	
	Unit price ($/ton)		42.27		42.27	
	Total monthly expense		2,086,447.20		2,086,447.20	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,872)		(1,872)	
	Unit price ($/ton)	i	42.27		42.27	
	Total adjustment expense		(79,129.44)		(79,129.44)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		1,493.451		1,493	
	Unit price ($/mcf)		4.62		4.62	
	Total monthly expense - bill in Dec	q	6,899.74		6,899.74	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	45,235		45,235	
	Unit price ($/gallon) - Calculated		1.38		1.38	
	Total monthly expense		62,424.30		62,424.30	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		2,076,641.80		2,076,641.80	
Total Operating Costs plus Fuel Consumption			4,387,959.14	0	4,387,959.13	

DTE Energy

2-17-2020

Ms. Andrea Gamelin
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Ms. Gamelin;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	1-31-2020	Actual	
Construction and Retirement Work in Progress		$ 1,331,717.91	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 920,524.19	5010-0000-002-03
Plant Operating Expenses		$ 1,440,652.08	See attached page
Total Actual Expenses		$ 3,692,894.18	
			5010-0000-002-03
Total Amount Due Detroit Edison		$ 3,692,894.18	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
1-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 173,561.77	$ 32,299.85	5000-0000-002-03
501*	Fuel	$ 680,424.14	$ 126,626.93	5011-0000-002-03
502	Steam Expenses	$ 151,882.87	$ 28,265.40	5020-0000-002-03
505	Electric Expenses	$ 200,278.60	$ 37,271.85	5050-0000-002-03
506	Misc Steam Power Expenses	$ 1,008,009.92	$ 187,590.65	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 436,141.13	$ 81,165.86	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 1,450,732.96	$ 269,981.40	5120-0000-002-03
513	Maintenance - Elect Plant	$ 1,133,045.00	$ 210,859.68	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 426,923.61	$ 79,450.48	5140-0000-002-03
926	Pensions and Benefits	$ 671,000.00	$ 124,873.10	9260-0000-002-03
Total Direct Production O & M		$ 6,332,000.00	$ 1,178,385.20	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.9% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI Index ceiling based on March 07 $s

Total Production O&M $ 1,260,998

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 227,000.00	5.1297%	18.61%	$ 42,244.70	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ 1,314,743

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
1-31-2020

FERC Account	Account Description	MPPA	Total	
920	Administrative & General Salaries	**33,872.67**	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	**7,852.07**	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	**(5,606.64)**	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	**5,311.63**	556,370.74	9230-0000-002-03
926	Pension and Benefits	**69,748.38**	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	**163.99**	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	**2,623.87**	274,838.64	9300-0000-002-03
931	Rents	**943.03**	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	**114,909.00**	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
1-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	7,155,926.42	1,331,717.91	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	7,155,926.42	1,331,717.91	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
1-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment
Plant Capital Expenses:					
A	Construction and Retirement		1,331,717.91		1,331,717.91
A	Materials and Supplies (see note below)		0.00	0.00	0.00
	Total Plant Capital Expenses		$ 1,331,717.91	$ -	$ 1,331,717.91
Plant Operating Expenses					
I	Production O & M Expense		1,260,998		1,260,998
I	Payroll, Sales & Use Taxes		42,245		42,245
I	Fly Ash Disposal Fee		10,500		10,500
I	Waste Water Disposal Fee		1,000		1,000
			1,314,743		1,314,743
II	Admn & General Expense		114,909		114,909
II	Insurance Expense		11,000		11,000
II	Single Business Tax		0		0
	Total Plant Operating Expenses		1,440,652		1,440,652.08
Fuel Consumption:					
Coal	Monthly consumption (tons)	a	20,669 i		20,669
	Unit price ($/ton)		41.95		41.95
	Total monthly expense		866,968.62		866,968.62
	Inventory Adjustments (tons)	j	(1,404)		(1,404)
	Unit price ($/ton)	i	41.95		41.95
	Total adjustment expense		(58,891.28)		(58,891.28)
Natural Gas	Nat Gas Usage at BRPP (mcf)		4,524		4,524
	Unit price ($/mcf)		3.56		3.56
	Total monthly expense - bill in Dec	q	16,104.45		16,104.45
Oil	Monthly consumption (gallons)	c	52,360		52,360
	Unit price ($/gallon) - Calculated		1.84		1.84
	Total monthly expense		96,342.40		96,342.40
	Fuel Adjustment to Invoice-Jan				
Coal	Monthly consumption (gallons)		0		0
	Unit price ($/gallon) - Increase		0.00		-
	Total monthly expense		0.00		0
	Total Fuel Expense		920,524.19		920,524.19
Total Operating Costs plus Fuel Consumption			3,692,894.19	0	3,692,894.18

DTE Energy

3-17-2020

Ms. Andrea Gamelin
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Ms. Gamelin;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	2-29-2020	Actual	
Construction and Retirement Work in Progress		$ 1,705,128.83	See attached page
Materials and Supplies Inventory Changes Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 130,948.45	5010-0000-002-03
Plant Operating Expenses		$ 1,262,740.47	See attached page
Total Actual Expenses		$ 3,098,817.75	
			5010-0000-002-03
Total Amount Due Detroit Edison		$ 3,098,817.75	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
2-29-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 217,454.73	$ 40,468.32	5000-0000-002-03
501*	Fuel	$ 363,186.21	$ 67,588.95	5011-0000-002-03
502	Steam Expenses	$ 196,998.21	$ 36,661.37	5020-0000-002-03
505	Electric Expenses	$ 338,291.22	$ 62,956.00	5050-0000-002-03
506	Misc Steam Power Expenses	$ 490,613.23	$ 91,303.12	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 121,440.58	$ 22,600.09	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 1,851,055.33	$ 344,481.40	5120-0000-002-03
513	Maintenance - Elect Plant	$ 1,399,053.27	$ 260,363.81	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 36,907.22	$ 6,868.43	5140-0000-002-03
926	Pensions and Benefits	$ 371,000.00	$ 69,043.10	9260-0000-002-03
Total Direct Production O & M		$ 5,386,000.00	$ 1,002,334.59	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
'Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 1,084,948

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 217,000.00	5.1297%	18.61%	$ 40,383.70	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ 1,136,831

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
2-29-2020

FERC Account	Account Description	MPPA	Total	
920	Administrative & General Salaries	33,872.67	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,852.07	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.64)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.63	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,748.38	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.99	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.87	274,838.64	9300-0000-002-03
931	Rents	943.03	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$ 2,000	9250-0000-002-03
925	Transmission Liability Insurance		
	Total Company Insurance	$ 11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
2-29-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	9,162,433.27	1,705,128.83	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	9,162,433.27	1,705,128.83	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
2-29-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment
Plant Capital Expenses:					
A	Construction and Retirement		1,705,128.83		1,705,128.83
A	Materials and Supplies (see note below)		0.00	0.00	0.00
	Total Plant Capital Expenses		$ 1,705,128.83	$ -	$ 1,705,128.83
Plant Operating Expenses					
I	Production O & M Expense		1,084,948		1,084,948
I	Payroll, Sales & Use Taxes		40,384		40,384
I	Fly Ash Disposal Fee		10,500		10,500
I	Waste Water Disposal Fee		1,000		1,000
			1,136,831		1,136,831
II	Admn & General Expense		114,909		114,909
II	Insurance Expense		11,000		11,000
II	Single Business Tax		0		0
	Total Plant Operating Expenses		1,262,740		1,262,740.47
Fuel Consumption:					
Coal	Monthly consumption (tons)	a	0	i	0
	Unit price ($/ton)		41.94		41.94
	Total monthly expense		0.00		-
	Inventory Adjustments (tons)	j	0		0
	Unit price ($/ton)	i	41.94		41.94
	Total adjustment expense		0.00		-
Natural Gas	Nat Gas Usage at BRPP (mcf)		4,152		4,152
	Unit price ($/mcf)		3.11		3.11
	Total monthly expense - bill in Dec	q	12,913.81		12,913.81
Oil	Monthly consumption (gallons)	c	67,836		67,836
	Unit price ($/gallon) - Calculated		1.74		1.74
	Total monthly expense		118,034.64		118,034.64
	Fuel Adjustment to Invoice-Jan				
Coal	Monthly consumption (gallons)		0		0
	Unit price ($/gallon) - Increase		0.00		-
	Total monthly expense		0.00		0
	Total Fuel Expense		130,948.45		130,948.45
Total Operating Costs plus Fuel Consumption			3,098,817.75	0	3,098,817.75

DTE Energy

4-20-2020

Ms. Andrea Gamelin
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Ms. Gamelin;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	3-31-2020	Actual	
Construction and Retirement Work in Progress		$ 1,811,606.18	See attached page
Materials and Supplies Inventory Changes Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 1,057,134.42	5010-0000-002-03
Plant Operating Expenses		$ 1,199,094.26	See attached page
Total Actual Expenses		$ 4,067,834.86	
BRPP 2019 Coal Price True-Up		$ 283,810.42	5010-0000-002-03
Total Amount Due Detroit Edison		$ 4,351,645.28	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
3-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 273,904.14	$ 50,973.56	5000-0000-002-03
501*	Fuel	$ 520,582.28	$ 96,880.36	5011-0000-002-03
502	Steam Expenses	$ 198,123.77	$ 36,870.83	5020-0000-002-03
505	Electric Expenses	$ 52,280.28	$ 9,729.36	5050-0000-002-03
506	Misc Steam Power Expenses	$ 716,945.84	$ 133,423.62	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 166,605.66	$ 31,005.31	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 2,125,911.39	$ 395,632.11	5120-0000-002-03
513	Maintenance - Elect Plant	$ 690,872.93	$ 128,571.45	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 50,773.69	$ 9,448.98	5140-0000-002-03
926	Pensions and Benefits	$ 305,000.00	$ 56,760.50	9260-0000-002-03
Total Direct Production O & M		$ 5,101,000.00	$ 949,296.08	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available: applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 1,031,909

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 160,000.00	5.1297%	18.61%	$ 29,776	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ 1,073,185

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
3-31-2020

FERC Account	Account Description	Total	
920	Administrative & General Salaries	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	556,370.74	9230-0000-002-03
926	Pension and Benefits	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	274,838.64	9300-0000-002-03
931	Rents	98,778.48	9310-0000-002-03
408	Payroll/Overheads	0.00	9350-0000-002-03
	Total Co. A & G Expenses	12,036,811.82	
	Belle River A & G Allocation Factor	0.051297	
	Sub-total	617,455.95	
	MPPA's Entitlement	0.1861	
	MPPA's Share - A & G Expenses	114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$ 2,000	9250-0000-002-03
925	Transmission Liability Insurance		
	Total Company Insurance	$ 11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
3-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	9,734,584.51	1,811,606.18	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	9,734,584.51	1,811,606.18	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
3-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment
Plant Capital Expenses:					
A	Construction and Retirement		1,811,606.18		1,811,606.18
A	Materials and Supplies (see note below)		0.00	0.00	0.00
	Total Plant Capital Expenses		$ 1,811,606.18	$ -	$ 1,811,606.18
Plant Operating Expenses					
I	Production O & M Expense		1,031,909		1,031,909
I	Payroll, Sales & Use Taxes		29,776		29,776
I	Fly Ash Disposal Fee		10,500		10,500
I	Waste Water Disposal Fee		1,000		1,000
			1,073,185		1,073,185
II	Admn & General Expense		114,909		114,909
II	Insurance Expense		11,000		11,000
II	Single Business Tax		0		0
	Total Plant Operating Expenses		1,199,094		1,199,094.26
Fuel Consumption:					
Coal	Monthly consumption (tons)	a	25,297		25,297
	Unit price ($/ton)		41.94		41.94
	Total monthly expense		1,060,988.49		1,060,988.49
	Inventory Adjustments (tons)	j	(1,404)		(1,404)
	Unit price ($/ton)	i	41.94		41.94
	Total adjustment expense		(58,885.55)		(58,885.55)
Natural Gas	Nat Gas Usage at BRPP (mcf)		2,747		2,747
	Unit price ($/mcf)		3.28		3.28
	Total monthly expense - bill in Dec	q	9,010.82		9,010.82
Oil	Monthly consumption (gallons)	c	29,127		29,127
	Unit price ($/gallon) - Calculated		1.58		1.58
	Total monthly expense		46,020.66		46,020.66
	Annual Reconciliation-Coal				
Coal	Monthly consumption (gallons)		0		0
	Unit price ($/gallon) - Increase		0.00		-
	Total monthly expense		0.00		0
	Total Fuel Expense		1,057,134.42		1,057,134.42
Total Operating Costs plus Fuel Consumption			4,067,834.86	0	4,067,834.86

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
3-31-2020

FERC Account	Account Description	MPPA	Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$ 2,000	9250-0000-002-03
925	Transmission Liability Insurance		
	Total Company Insurance	$ 11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Capital Difference (118,013.16)
1066-2000-000-03

Revised Amount	$338,392.81
Original Amount	$456,405.97
Difference	($118,013.16)

REVISED 5-26-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	**4-30-2020**	**Actual**
Construction and Retirement Work in Progress-REVISED		$ 338,392.81
Materials and Supplies Inventory Changes-Adjust December Annual Charge		$ -
Fuel Consumption Expense		$ 625,780.31
Plant Operating Expenses		$ 915,477.87
Total Actual Expenses		$ 1,879,650.99

Total Amount Due Detroit Edison-REVISED	$ 1,879,650.99

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
4-30-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%
500	Oper Supervisn & Engineer'g	$ 475,136.71	$ 88,422.94
501*	Fuel	$ 706,667.92	$ 131,510.90
502	Steam Expenses	$ 289,903.70	$ 53,951.08
505	Electric Expenses	$ 208,136.87	$ 38,734.27
506	Misc Steam Power Expenses	$ 658,678.41	$ 122,580.05
510	Maint'ce Supervn & Enginr'g	$ -	$ -
511	Maintenance - Structures	$ 112,118.98	$ 20,865.34
512	Maintenance - Boiler Plant	$ (113,307.55)	$ (21,086.54)
513	Maintenance - Elect Plant	$ 743,251.21	$ 138,319.05
514	Maint'ce - Misc Steam Plt	$ 258,413.76	$ 48,090.80
926	Pensions and Benefits	$ 277,000.00	$ 51,549.70
Total Direct Production O & M		$3,616,000.00	$ 672,937.59

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%
500	Oper Supervisn & Engineer'g	0	0	0
501*	Fuel	262,679	41,410	7,706.40
502	Steam Expenses	0	0	0
505	Electric Expenses	0	0	0
506	Misc Steam Power Expenses	792,361	124,912	23,246.08
510	Maint'ce Supervn & Enginr'g	0	0	0
511	Maintenance - Structures	0	0	0
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86
513	Maintenance - Elect Plant	0	0	0
514	Maint'ce - Misc Steam Plt	0	0	0
926	Pensions and Benefits	588,452	92,766	17,263.84
Total Support Services O&M		2,815,936	443,918	82,613.18

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 755,551

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share
408001	Payroll, S & U Taxes	$ 121,000.00	5.1297%	18.61 %	$ 22,518
	Fly Ash Disp Fee (as budgeted)				$ 10,500
	Waste Water Disposal Fee (as budgeted)				$ 1,000

Total Plant O&M $ 789,569

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
4-30-2020

FERC Account	Account Description	Total
920	Administrative & General Salaries	3,548,016.59
921	Office Supplies & Expenses	822,471.15
922	Admn Expenses Transferred - Credit	(587,271.39)
923	Outside Services Employed	556,370.74
926	Pension and Benefits	7,306,430.10
928	Regulatory Commission Expenses	17,177.51
930	General Advertising & Misc Expenses	274,838.64
931	Rents	98,778.48
408	Payroll/Overheads	0.00
	Total Co. A & G Expenses	12,036,811.82
	Belle River A & G Allocation Factor	0.051297
	Sub-total	617,455.95
	MPPA's Entitlement	0.1861
	MPPA's Share - A & G Expenses	114,909.00

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000
924	Liability Payments to Third Parties	$ 2,000
925	Transmission Liability Insurance	
	Total Company Insurance	$ 11,000

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
4-30-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%
106	Completed construction not classified	$ -	0.00
107	Construction work in progress	1,818,338.56	338,392.81
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00
	MPPA's Share - Plant Improvements	1,818,338.56	338,392.81

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61 %
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
4-30-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment
Plant Capital Expenses:					
A	Construction and Retirement		338,392.81		338,392.81
A	Materials and Supplies (see note below)		0.00	0.00	0.00
	Total Plant Capital Expenses		$ 338,392.81	$ -	$ 338,392.81
Plant Operating Expenses					
I	Production O & M Expense		755,551		755,551
I	Payroll, Sales & Use Taxes		22,518		22,518
I	Fly Ash Disposal Fee		10,500		10,500
I	Waste Water Disposal Fee		1,000		1,000
			789,569		789,569
II	Admn & General Expense		114,909		114,909
II	Insurance Expense		11,000		11,000
II	Single Business Tax		0		0
	Total Plant Operating Expenses		915,478		915,477.87
Fuel Consumption:					
Coal	Monthly consumption (tons)	a	15,550	i	15,550
	Unit price ($/ton)		41.64		41.64
	Total monthly expense		647,502.00		647,502.00
	Inventory Adjustments (tons)	j	(1,404)		(1,404)
	Unit price ($/ton)	i	41.64		41.64
	Total adjustment expense		(58,462.56)		(58,462.56)
Natural Gas	Nat Gas Usage at BRPP (mcf)		5,363		5,363
	Unit price ($/mcf)		0.28		0.28
	Total monthly expense - bill in Dec	q	1,501.70		1,501.70
Oil	Monthly consumption (gallons)	c	22,163		22,163
	Unit price ($/gallon) - Calculated		1.59		1.59
	Total monthly expense		35,239.17		35,239.17
	Annual Reconciliation-Coal				
Coal	Monthly consumption (gallons)		0		0
	Unit price ($/gallon) - Increase		0.00		-
	Total monthly expense		0.00		0
	Total Fuel Expense		625,780.31		625,780.31
Total Operating Costs plus Fuel Consumption			1,879,651.00	0	1,879,650.99

DTE Energy

6-17-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	5-31-2020	Actual	
Construction and Retirement Work in Progress		$ 1,902,421.14	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 1,170,152.75	See attached page
Plant Operating Expenses		$ 635,955.68	See attached page
Total Actual Expenses		$ 3,708,529.57	
Credit Memo-Gas Price Adjustment-Jan through Mar, 2020		$ (33,932.31)	
Total Amount Due Detroit Edison		$ 3,674,597.26	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact DTE Energy at (313) 235-8483 as notification to DTE of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
5-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 251,706.22	$ 46,842.53	5000-0000-002-03
501*	Fuel	$ 387,544.17	$ 72,121.97	5011-0000-002-03
502	Steam Expenses	$ 141,996.51	$ 26,425.55	5020-0000-002-03
505	Electric Expenses	$ 174,547.06	$ 32,483.21	5050-0000-002-03
506	Misc Steam Power Expenses	$ 316,346.18	$ 58,872.02	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 100,687.15	$ 18,737.88	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 932,084.16	$ 173,460.86	5120-0000-002-03
513	Maintenance - Elect Plant	$ (544,439.84)	$ (101,320.25)	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 60,528.39	$ 11,264.33	5140-0000-002-03
926	Pensions and Benefits	$ 334,000.00	$ 62,157.40	9260-0000-002-03
Total Direct Production O & M		$ 2,155,000.00	$ 401,045.50	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI Index ceiling based on March 07 $s

Total Production O&M	**$ 483,659**

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 80,000.00	5.1297%	18.61%	$ 14,888	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M	**$ 510,047**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
5-31-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
5-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	10,222,574.62	1,902,421.14	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	10,222,574.62	1,902,421.14	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
5-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		1,902,421.14		1,902,421.14	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 1,902,421.14	$ -	$ 1,902,421.14	
Plant Operating Expenses						
I	Production O & M Expense		483,659		483,659	
I	Payroll, Sales & Use Taxes		14,888		14,888	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			510,047		510,047	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		635,956		635,955.68	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	29,405 i		29,405	
	Unit price ($/ton)		41.38		41.38	
	Total monthly expense		1,216,778.90		1,216,778.90	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,404)		(1,404)	
	Unit price ($/ton)	i	41.38		41.38	
	Total adjustment expense		(58,097.52)		(58,097.52)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		196		196	
	Unit price ($/mcf)		4.68		4.68	
	Total monthly expense - bill in Dec	q	915.36		915.36	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	6,639		6,639	
	Unit price ($/gallon) - Calculated		1.59		1.59	
	Total monthly expense		10,556.01		10,556.01	5000-0000-002-03
	Annual Reconcilliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		1,170,152.75		1,170,152.75	
Total Operating Costs plus Fuel Consumption			3,708,529.57	0	3,708,529.57	

DTE Energy

7-16-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	6-30-2020	**Actual**	
Construction and Retirement Work in Progress-REVISED		$ 1,104,192.13	See attached page
Materials and Supplies Inventory Changes Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 1,171,581.55	See attached page
Plant Operating Expenses		$ 1,025,090.78	See attached page
Total Actual Expenses		$ 3,300,864.46	

Total Amount Due Detroit Edison $ 3,300,864.46

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
6-30-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 233,796.62	$ 43,509.55	5000-0000-002-03
501*	Fuel	$ 413,025.01	$ 76,863.95	5011-0000-002-03
502	Steam Expenses	$ 168,844.82	$ 31,422.02	5020-0000-002-03
505	Electric Expenses	$ 190,989.52	$ 35,543.15	5050-0000-002-03
506	Misc Steam Power Expenses	$ 625,600.30	$ 116,424.22	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 131,981.59	$ 24,561.77	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 982,101.61	$ 182,769.11	5120-0000-002-03
513	Maintenance - Elect Plant	$ 778,171.67	$ 144,817.75	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 387,488.87	$ 72,111.68	5140-0000-002-03
926	Pensions and Benefits	$ 309,000.00	$ 57,504.90	9260-0000-002-03
Total Direct Production O & M		$ 4,221,000.00	$ 785,528.10	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ **868,141**

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 105,000.00	5.1297%	18.61%	$ 19,541	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ **899,182**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
6-30-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
6-30-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	5,933,326.88	1,104,192.13	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	5,933,326.88	1,104,192.13	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
6-30-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		1,104,192.13		1,104,192.13	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 1,104,192.13	$ -	$ 1,104,192.13	
Plant Operating Expenses						
I	Production O & M Expense		868,141		868,141	
I	Payroll, Sales & Use Taxes		19,541		19,541	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			899,182		899,182	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		1,025,091		1,025,090.78	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	29,471		29,471	
	Unit price ($/ton)		41.38		41.38	
	Total monthly expense		1,219,509.98		1,219,509.98	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,404)		(1,404)	
	Unit price ($/ton)	i	41.38		41.38	
	Total adjustment expense		(58,097.52)		(58,097.52)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		5		5	
	Unit price ($/mcf)		41.40		41.40	
	Total monthly expense - bill in Dec	q	215.69		215.69	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	6,260		6,260	
	Unit price ($/gallon) - Calculated		1.59		1.59	
	Total monthly expense		9,953.40		9,953.40	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		1,171,581.55		1,171,581.55	
Total Operating Costs plus Fuel Consumption			3,300,864.47	0	3,300,864.46	

DTE Energy

8-17-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses: 7-31-2020	**Actual**	
Construction and Retirement Work in Progress-REVISED	$ 744,246.59	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge	$ -	1540-0000-000-03
Fuel Consumption Expense	$ 1,391,159.66	See attached page
Plant Operating Expenses	$ 864,300.39	See attached page
Total Actual Expenses	$ 2,999,706.64	
2017 Annual Reconciliation True-Up	$ 425,945.13	1420-0000-000-03
2017 Annual Reconciliation True-Up	$ (563,772.30)	1066-2000-000-03
Total Amount Due Detroit Edison	$ 2,861,879.47	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Please contact Karoline Sheldon at (313) 235-8483 as notification to Detroit Edison of the wire transfer.

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
7-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 252,240.92	$ 46,942.04	5000-0000-002-03
501*	Fuel	$ 554,696.40	$ 103,229.00	5011-0000-002-03
502	Steam Expenses	$ 185,441.80	$ 34,510.72	5020-0000-002-03
505	Electric Expenses	$ 188,985.57	$ 35,170.21	5050-0000-002-03
506	Misc Steam Power Expenses	$ 404,791.80	$ 75,331.75	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 128,121.04	$ 23,843.33	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 591,463.39	$ 110,071.34	5120-0000-002-03
513	Maintenance - Elect Plant	$ 362,823.00	$ 67,521.36	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 322,436.08	$ 60,005.36	5140-0000-002-03
926	Pensions and Benefits	$ 369,000.00	$ 68,670.90	9260-0000-002-03
Total Direct Production O & M		$ 3,360,000.00	$ 625,296.01	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI Index ceiling based on March 07 $s

Total Production O&M $ **707,909**

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 102,000.00	5.1297%	18.61%	$ 18,982	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ **738,391**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
7-31-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$ 2,000	9250-0000-002-03
925	Transmission Liability Insurance		
	Total Company Insurance	$ 11,000	

Single Business Tax **(billed annually as part of April actual expenses)**

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
7-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	3,999,175.67	744,246.59	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	3,999,175.67	744,246.59	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
7-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		744,246.59		744,246.59	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 744,246.59	$ -	$ 744,246.59	
Plant Operating Expenses						
I	Production O & M Expense		707,909		707,909	
I	Payroll, Sales & Use Taxes		18,982		18,982	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			738,391		738,391	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		864,300		864,300.39	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	33,068		33,068	
	Unit price ($/ton)		41.92		41.92	
	Total monthly expense		1,386,210.56		1,386,210.56	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,404)		(1,404)	
	Unit price ($/ton)	i	41.92		41.92	
	Total adjustment expense		(58,855.68)		(58,855.68)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		0		0	
	Unit price ($/mcf)		0.00		-	
	Total monthly expense - bill in Dec	q	0.00		0.00	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	42,822		42,822	
	Unit price ($/gallon) - Calculated		1.49		1.49	
	Total monthly expense		63,804.78		63,804.78	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		1,391,159.66		1,391,159.66	
Total Operating Costs plus Fuel Consumption			2,999,706.64	0	2,999,706.64	

DTE Energy

9-15-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	8-31-2020	**Actual**	
Construction and Retirement Work in Progress-REVISED		$ 540,939.80	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 2,301,332.09	See attached page
Plant Operating Expenses		$ 805,864.98	See attached page
Total Actual Expenses		$ 3,648,136.87	

Total Amount Due Detroit Edison $ 3,648,136.87

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
8-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 199,554.71	$ 37,137.13	5000-0000-002-03
501*	Fuel	$ 375,902.04	$ 69,955.37	5011-0000-002-03
502	Steam Expenses	$ 163,562.29	$ 30,438.94	5020-0000-002-03
505	Electric Expenses	$ 191,999.04	$ 35,731.02	5050-0000-002-03
506	Misc Steam Power Expenses	$ 496,345.76	$ 92,369.95	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 126,500.40	$ 23,541.72	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 638,042.48	$ 118,739.71	5120-0000-002-03
513	Maintenance - Elect Plant	$ 171,667.92	$ 31,947.40	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 325,425.35	$ 60,561.66	5140-0000-002-03
926	Pensions and Benefits	$ 359,000.00	$ 66,809.90	9260-0000-002-03
Total Direct Production O & M		$ 3,048,000.00	$ 567,232.80	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI index of 2.5% as ceiling for Monthly Support Service Costs

*Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 649,846

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 100,000.00	5.1297%	18.61%	$ 18,610	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ 679,956

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
8-31-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
8-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	2,906,715.74	540,939.80	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	2,906,715.74	540,939.80	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
8-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		540,939.80		540,939.80	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 540,939.80	$ -	$ 540,939.80	
Plant Operating Expenses						
I	Production O & M Expense		649,846		649,846	
I	Payroll, Sales & Use Taxes		18,610		18,610	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			679,956		679,956	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		805,865		805,864.98	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	53,672 i		53,672	
	Unit price ($/ton)		41.92		41.92	
	Total monthly expense		2,249,930.24		2,249,930.24	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,404)		(1,404)	
	Unit price ($/ton)	i	41.92		41.92	
	Total adjustment expense		(58,855.68)		(58,855.68)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		3,089		3,089	
	Unit price ($/mcf)		2.98		2.98	
	Total monthly expense - bill in Dec	q	9,205.98		9,205.98	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	74,853		74,853	
	Unit price ($/gallon) - Calculated		1.35		1.35	
	Total monthly expense		101,051.55		101,051.55	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		2,301,332.09		2,301,332.09	
Total Operating Costs plus Fuel Consumption			3,648,136.88	0	3,648,136.87	

DTE Energy

10-16-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	9-30-2020	Actual	
Construction and Retirement Work in Progress-REVISED		$ 429,511.74	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 2,328,763.02	See attached page
Plant Operating Expenses		$ 894,076.38	See attached page
Total Actual Expenses		$ 3,652,351.14	

Total Amount Due Detroit Edison $ 3,652,351.14

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
9-30-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 239,213.56	$ 44,517.64	5000-0000-002-03
501*	Fuel	$ 743,055.99	$ 138,282.72	5011-0000-002-03
502	Steam Expenses	$ 227,492.69	$ 42,336.39	5020-0000-002-03
505	Electric Expenses	$ 198,776.21	$ 36,992.25	5050-0000-002-03
506	Misc Steam Power Expenses	$ 512,677.62	$ 95,409.30	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 168,032.38	$ 31,270.83	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 911,579.21	$ 169,644.89	5120-0000-002-03
513	Maintenance - Elect Plant	$ 35,991.76	$ 6,698.07	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 198,180.58	$ 36,881.41	5140-0000-002-03
926	Pensions and Benefits	$ 316,000.00	$ 58,807.60	9260-0000-002-03
Total Direct Production O & M		$ 3,551,000.00	$ 660,841.10	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M $ 743,454

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 71,000.00	5.1297%	18.61%	$ 13,213	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M **$ 768,167**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
9-30-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$ 9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$ 2,000	9250-0000-002-03
925	Transmission Liability Insurance		
	Total Company Insurance	$ 11,000	

Single Business Tax **(billed annually as part of April actual expenses)**

408	MPPA's share of Single Business Tax	$ -

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
9-30-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	2,307,962.07	429,511.74	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	2,307,962.07	429,511.74	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
9-30-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		429,511.74		429,511.74	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 429,511.74	$ -	$ 429,511.74	
Plant Operating Expenses						
I	Production O & M Expense		743,454		743,454	
I	Payroll, Sales & Use Taxes		13,213		13,213	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			768,167		768,167	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		894,076		894,076.38	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	56,185 i		56,185	
	Unit price ($/ton)		42.07		42.07	
	Total monthly expense		2,363,702.95		2,363,702.95	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,404)		(1,404)	
	Unit price ($/ton)	i	42.07		42.07	
	Total adjustment expense		(59,066.28)		(59,066.28)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		0.372		0	
	Unit price ($/mcf)		75.95		75.95	
	Total monthly expense - bill in Dec	q	28.25		28.25	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	18,537		18,537	
	Unit price ($/gallon) - Calculated		1.30		1.30	
	Total monthly expense		24,098.10		24,098.10	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		2,328,763.02		2,328,763.02	
Total Operating Costs plus Fuel Consumption			3,652,351.15	0	3,652,351.14	

DTE Energy

11-16-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	10-31-2020	Actual	
Construction and Retirement Work in Progress		$ 466,132.38	See attached page
Materials and Supplies Inventory Changes - Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 3,134,742.26	See attached page
Plant Operating Expenses		$ 965,910.98	See attached page
Total Actual Expenses		$ 4,566,785.62	
2018 Annual True-Up		$ 254,838.41	See Below
		$ 255,010.37	5100-0000-002-03
		$ (171.96)	1066-2000-000-03
2019 Annual True-Up		$ (313,965.49)	See Below
		$ (460,000.00)	1650-0000-002-03
		$ 146,034.69	5100-0000-002-03
		$ (0.18)	1066-2000-000-03
Total Amount Due Detroit Edison		$ 4,507,658.54	

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #1 1028-23

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
10-31-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 244,198.87	$ 45,445.41	5000-0000-002-03
501*	Fuel	$ 619,454.68	$ 115,280.52	5011-0000-002-03
502	Steam Expenses	$ 205,572.31	$ 38,257.01	5020-0000-002-03
505	Electric Expenses	$ 152,752.74	$ 28,427.29	5050-0000-002-03
506	Misc Steam Power Expenses	$ 916,919.58	$ 170,638.73	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 248,500.33	$ 46,245.91	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 881,622.09	$ 164,069.87	5120-0000-002-03
513	Maintenance - Elect Plant	$ 22,346.33	$ 4,158.65	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 356,633.06	$ 66,369.41	5140-0000-002-03
926	Pensions and Benefits	$ 288,000.00	$ 53,596.80	9260-0000-002-03
Total Direct Production O & M		$ 3,936,000.00	$ 732,489.60	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Enginr'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs
*Note: Actuals for August 07 Support Svs not available; applied monthly CPI index ceiling based on March 07 $s

Total Production O&M	**$ 815,103**

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 72,000.00	5.1297%	18.61%	$ 13,399	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M	**$ 840,002**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
10-31-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
10-31-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	2,504,741.44	466,132.38	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	2,504,741.44	466,132.38	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
10-31-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		466,132.38		466,132.38	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 466,132.38	$ -	$ 466,132.38	
Plant Operating Expenses						
I	Production O & M Expense		815,103		815,103	
I	Payroll, Sales & Use Taxes		13,399		13,399	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			840,002		840,002	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		965,911		965,910.98	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	75,771	i	75,771	
	Unit price ($/ton)		42.27		42.27	
	Total monthly expense		3,202,840.17		3,202,840.17	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,872)		(1,872)	
	Unit price ($/ton)	i	42.27		42.27	
	Total adjustment expense		(79,129.44)		(79,129.44)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		3,116.243		3,116	
	Unit price ($/mcf)		1.11		1.11	
	Total monthly expense - bill in Dec	q	3,459.03		3,459.03	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	5,825		5,825	
	Unit price ($/gallon) - Calculated		1.30		1.30	
	Total monthly expense		7,572.50		7,572.50	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		3,134,742.26		3,134,742.26	
Total Operating Costs plus Fuel Consumption			4,566,785.62	0	4,566,785.62	

DTE Energy

12-17-2020

Mr Ben Rowland
Financial Accountant
Michigan Public Power Agency
809 Centennial Way
Lansing, Michigan 48917

Dear Mr. Rowland;

Invoice for Costs Associated with the Belle River Participation Agreement dated December 1, 1982:

The following amount is now due pursuant to the appropriate sections of the

Actual expenses:	11-30-2020	Actual	
Construction and Retirement Work in Progress		$ 381,857.19	See attached page
Materials and Supplies Inventory Changes Adjust December Annual Charge		$ -	1540-0000-000-03
Fuel Consumption Expense		$ 3,004,809.96	See attached page
Plant Operating Expenses		$ 1,012,249.89	See attached page
Total Actual Expenses		$ 4,398,917.04	

Total Amount Due Detroit Edison $ 4,398,917.04

The payment invoiced herein shall be made by wire transfer to:

JP Morgan - Chase Bank
N. A. Detroit
ABA #072000326
Benef. Detroit Edison
Account #11028-23

Sincerely,

Cathy Turkus (810) 326-3295
Senior Financial Analyst
DTE Controller/Fossil Generation

DTE Energy

Schedule II
BELLE RIVER Power Plant
Production O&M-Direct, Support Services and Other O&M
11-30-2020

Direct Production O&M:

FERC Account	Account Description	Production* O & M	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	$ 288,449.59	$ 53,680.47	5000-0000-002-03
501*	Fuel	$ 466,583.81	$ 86,831.25	5011-0000-002-03
502	Steam Expenses	$ 190,074.79	$ 35,372.92	5020-0000-002-03
505	Electric Expenses	$ 309,476.69	$ 57,593.61	5050-0000-002-03
506	Misc Steam Power Expenses	$ 1,137,809.99	$ 211,746.44	5060-0000-002-03
510	Maint'ce Supervn & Engin'g	$ -	$ -	5100-0000-002-03
511	Maintenance - Structures	$ 337,177.23	$ 62,748.68	5110-0000-002-03
512	Maintenance - Boiler Plant	$ 878,393.01	$ 163,468.94	5120-0000-002-03
513	Maintenance - Elect Plant	$ 29,466.07	$ 5,483.64	5130-0000-002-03
514	Maint'ce - Misc Steam Plt	$ 255,568.82	$ 47,561.36	5140-0000-002-03
926	Pensions and Benefits	$ 301,000.00	$ 56,016.10	9260-0000-002-03
Total Direct Production O & M		$ 4,194,000.00	$ 780,503.41	

Support Services Costs:**

FERC Account	Account Description	Production* O & M	BRPP Allocation 15.76%	MPPA's Entitlement 18.61%	
500	Oper Supervisn & Engineer'g	0	0	0	
501*	Fuel	262,679	41,410	7,706.40	5011-0000-002-03
502	Steam Expenses	0	0	0	
505	Electric Expenses	0	0	0	
506	Misc Steam Power Expenses	792,361	124,912	23,246.08	5060-0000-002-03
510	Maint'ce Supervn & Engin'g	0	0	0	
511	Maintenance - Structures	0	0	0	
512	Maintenance - Boiler Plant	1,172,445	184,830	34,396.86	5120-0000-002-03
513	Maintenance - Elect Plant	0	0	0	
514	Maint'ce - Misc Steam Plt	0	0	0	
926	Pensions and Benefits	588,452	92,766	17,263.84	9260-0000-002-03
Total Support Services O&M		2,815,936	443,918	82,613.18	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly Support Service Costs

*Note: Actuals for August 07 Support Svs not available; applied monthly CPI Index ceiling based on March 07 $s

Total Production O&M $ 863,117

Other Production-Related Costs:

		Total BRPP Expense		MPPA's Entitlement	MPPA's Share	
408001	Payroll, S & U Taxes	$ 63,000.00	5.1297%	18.61%	$ 11,724	4083-0000-002-03
	Fly Ash Disp Fee (as budgeted)				$ 10,500	5021-0000-002-03
	Waste Water Disposal Fee (as budgeted)				$ 1,000	5021-0000-002-03

Total Plant O&M $ **886,341**

DTE Energy

Schedule III
BELLE RIVER Power Plant
Administrative and General Expenses**
11-30-2020

FERC Account	Account Description		Total	
920	Administrative & General Salaries	33,870.69	3,548,016.59	9200-0000-002-03
921	Office Supplies & Expenses	7,851.62	822,471.15	9210-0000-002-03
922	Admn Expenses Transferred - Credit	(5,606.31)	(587,271.39)	9220-0000-002-03
923	Outside Services Employed	5,311.32	556,370.74	9230-0000-002-03
926	Pension and Benefits	69,751.02	7,306,430.10	9260-0000-002-03
928	Regulatory Commission Expenses	163.98	17,177.51	9280-0000-002-03
930	General Advertising & Misc Expenses	2,623.71	274,838.64	9300-0000-002-03
931	Rents	942.98	98,778.48	9310-0000-002-03
408	Payroll/Overheads	-	0.00	9350-0000-002-03
	Total Co. A & G Expenses	114,909.00	12,036,811.82	
	Belle River A & G Allocation Factor		0.051297	
	Sub-total		617,455.95	
	MPPA's Entitlement		0.1861	
	MPPA's Share - A & G Expenses		114,909.00	

** Beginning 2007 using 2006 CPI Index of 2.5% as ceiling for Monthly A&G Costs
*Note: Actuals for August 07 A&G not available; applied monthly CPI Index ceiling based on March 07 $s

Property and Liability Insurance (reflects MPPA's cost):

924	Fire & Boiler Protection Insurance	$	9,000	9240-0000-002-03
924	Liability Payments to Third Parties	$	2,000	9250-0000-002-03
925	Transmission Liability Insurance			
	Total Company Insurance	$	11,000	

Single Business Tax (billed annually as part of April actual expenses)

408	MPPA's share of Single Business Tax	$	-

DTE Energy

Schedule IV
BELLE RIVER Power Plant
Construction, Retirement and Inventory
11-30-2020

FERC Account	Account Description	Belle River	MPPA's Entitlement 18.61%	
106	Completed construction not classified	$ -	0.00	
107	Construction work in progress	2,051,892.47	381,857.19	1066-2000-000-03
108	Retirement work in progress (accumulated reserve for depr.)	0.00	0.00	1086-2000-002-03
	MPPA's Share - Plant Improvements	2,051,892.47	381,857.19	

FERC Account	Account Description	Current Year Balance Belle River	less Prior Year Balance	Change from Prior Month
154 - 101540	Plant materials and operating supplies	17,427,590.88	17,427,590.88	$ -
	(see note on previous page regarding M&S)			
	MPPA's Entitlement			18.61%
	MPPA's Share - Plant Improvements			$ -

DTE Energy

Summary
Belle River Power Plant
Actual Compared to Estimated Expenses
11-30-2020

Schedule	Item		Actual Operating Costs MPPA's Share		Adjustment	
Plant Capital Expenses:						
A	Construction and Retirement		381,857.19		381,857.19	
A	Materials and Supplies (see note below)		0.00	0.00	0.00	
	Total Plant Capital Expenses		$ 381,857.19	$ -	$ 381,857.19	
Plant Operating Expenses						
I	Production O & M Expense		863,117		863,117	
I	Payroll, Sales & Use Taxes		11,724		11,724	
I	Fly Ash Disposal Fee		10,500		10,500	
I	Waste Water Disposal Fee		1,000		1,000	
			886,341		886,341	
II	Admn & General Expense		114,909		114,909	
II	Insurance Expense		11,000		11,000	
II	Single Business Tax		0		0	
	Total Plant Operating Expenses		1,012,250		1,012,249.89	
Fuel Consumption:						
Coal	Monthly consumption (tons)	a	72,599		72,599	
	Unit price ($/ton)		42.27		42.27	
	Total monthly expense		3,068,759.73		3,068,759.73	5010-0000-002-03
	Inventory Adjustments (tons)	j	(1,872)		(1,872)	
	Unit price ($/ton)		42.27		42.27	
	Total adjustment expense		(79,129.44)		(79,129.44)	5010-0000-002-03
Natural Gas	Nat Gas Usage at BRPP (mcf)		347.821		348	
	Unit price ($/mcf)		4.51		4.51	
	Total monthly expense - bill in Dec	q	1,568.67		1,568.67	5010-0000-002-03
Oil	Monthly consumption (gallons)	c	10,470		10,470	
	Unit price ($/gallon) - Calculated		1.30		1.30	
	Total monthly expense		13,611.00		13,611.00	5000-0000-002-03
	Annual Reconciliation-Coal					
Coal	Monthly consumption (gallons)		0		0	
	Unit price ($/gallon) - Increase		0.00		-	
	Total monthly expense		0.00		0	
	Total Fuel Expense		3,004,809.96		3,004,809.96	
Total Operating Costs plus Fuel Consumption			4,398,917.04	0	4,398,917.04	

MPSC Case No.:	U-20528
Requestor:	MEC
Question No.:	MECDE-4.1
Respondent:	S. C. Dauss
Page:	1 of 1

Question: Provide for each month in 2020 the MPPA share of generation from Belle River, and the amounts billed to MPPA for energy and for capacity each month in 2020.

Answer: Please see the table below for MPPA's monthly share of generation from Belle River. The Company does not bill MPPA for energy or capacity. MPPA is its own MISO market participant. Energy and capacity billing for MPPA's share of Belle River is conducted between MPPA and MISO.

Month	MPPA Share of Generation (Net MWh)
Jan	33,935
Feb	(830)
Mar	40,244
Apr	24,753
May	47,497
Jun	50,757
Jul	57,394
Aug	90,918
Sep	96,011
Oct	134,068
Nov	127,459
Dec	84,625
Total	**786,831**

Attachments: None.

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: 9320050003
INVOICE DATE: 1/26/21

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
JAN 2021	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF DEC 2020	$63,126.27	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF DEC 2020	$1,512.75	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF DEC 2020	0.00	

PAYMENT DUE BY 2/15/21

AMOUNT DUE $64,639.02

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 2/15/21

INVOICE STATEMENT NO: 9320050003

MICHIGAN PUBLIC POWER AGENCY

1/26/21

Schedule I

CONSUMERS ENERGY COMPANY
MPPA'S CONSTRUCTION COSTS
CAMPBELL #3
2020

MONTH CHARGES INCURRED	BILLING DATE	INVOICE #	$ AMOUNT	YTD $ AMOUNT
JAN	2/25/20	9317698723	$20,473.49	$20,473.49
FEB	3/18/20	9317885972	$56,386.24	$76,859.73
MAR	4/23/20	9318133206	$24,036.38	$100,896.11
APR	5/7/20	9318383860	$13,815.11	$114,711.22
MAY	6/18/20	9318554040	$39,850.04	$154,561.26
JUN	7/23/20	9318733215	$35,022.27	$189,583.53
JUL	8/25/20	9319018231	$32,898.31	$222,481.84
AUG	9/16/20	9319170652	$53,304.85	$275,786.69
SEPT	10/20/20	9319403269	$53,239.05	$329,025.74
OCT	11/19/20	9319513290	$60,437.81	$389,463.55
NOV	12/16/20	9319783624	$50,332.55	$419,322.61
DEC	1/26/21	9320050003	$63,126.27	$426,062.64

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319929125
INVOICE DATE: 1/7/21

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
JAN 2021	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR DEC 2020 REFERENCE EXHIBIT I	$403,080.64

PAYMENT DUE BY 1/20/21 AMOUNT DUE $403,080.64

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

PAYMENT DUE BY 1/20/21

INVOICE STATEMENT NO: 9319929125

MICHIGAN PUBLIC POWER AGENCY

0
1/7/21

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

DECEMBER 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,468
ADJUSTMENTS	0
WESTERN BURN:	(10,274)
EASTERN BURN:	(642)

ACTUAL COST:

WESTERN RECEIPTS	10,930
FUEL COSTS - WESTERN	$374,343.48
HANDLING COST - WESTERN	8,011.97
LIME CHARGES	12,247.19
UREA CHARGES	4,374.94
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	60,725
PRICE PER GALLON	$1.3327
% OF TOTAL BURN:	5.07%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

DECEMBER 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,468
ADJUSTMENTS	0
BURN	(10,916)
ENDING BALANCE	2,552
CONTRACTUAL BALANCE	13,482
DECEMBER RECEIPTS	10,930

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

DECEMBER 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$374,343.48	
HANDLING			$8,011.97	
LIME CHARGES			12,247.19	
UREA CHARGES			4,374.94	
ACT. CARB.			-	
TONS (WET)		10,930		
UNIT PRICE		$37		
	TOTAL		$398,977.58	$398,977.58
	AUX GEN FUEL COST (EXHIBIT IIA)			$4,103.06
	TOTAL INVOICE TO MPPA			$403,080.64

Fuel	Fuel Hdlg	
$378,446.54	$24,634.10	$403,080.64
1510-0000-000-02	5011-0000-001-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

DECEMBER 2020 ACTUAL

FUEL OIL USED IN GENERATION	60,725	GALS
PRICE PER GALLON	$1.3327	
TOTAL	$80,928.21	
MPPA % OF BURN	0.0507	
MPPA AUXILIARY FUEL COST	$4,103.06	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319951783
INVOICE DATE: 1/11/21

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
JAN 2021		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF DEC 2020	$205,346.13

PAYMENT DUE BY 1/20/21

AMOUNT DUE $205,346.13

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 1/20/21

INVOICE STATEMENT NO: 9319951783

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
DEC 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$153,127.21	See Sched I
II	Gen Office Eng & Suprv - Allocation	$26,377.10	See Sched II
III	Employee Benefits	$2,601.10	**9260-0000-001-02**
IV	Payroll Taxes	$7,323.11	**4083-0000-001-02**
V	Admin & General Expenses	$15,917.60	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$205,346.13	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
DEC 2020 ACTUAL

FERC Account			Labor	Other	Total
500	5000-0000-001-02	11,135.94	$197,198.35	$34,800.31	$231,998.66
501	5011-0000-001-02	20,328.33	$332,207.54	$91,299.34	$423,506.88
502	5020-0000-001-02	24,209.58	$439,159.72	$65,206.58	$504,366.30
505	5050-0000-001-02	10,014.48	$205,891.53	$2,743.39	$208,634.92
506	5060-0000-001-02	6,400.71	$39,979.90	$93,368.29	$133,348.19
510	5100-0000-001-02	6,544.39	$131,114.66	$5,226.89	$136,341.55
511	5110-0000-001-02	4,939.31	$41,543.16	$61,359.03	$102,902.19
512	5120-0000-001-02	62,964.49	$318,765.31	$992,994.80	$1,311,760.11
513	5130-0000-001-02	4,752.79	$65,510.97	$33,505.44	$99,016.41
514	5140-0000-001-02	1,837.19	$24,017.86	$14,257.18	$38,275.04
Total		153,127.21	$1,795,389.00	$1,394,761.25	$3,190,150.25
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$86,178.67	$66,948.54	$153,127.21

Schedule I-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Production Expenses
DEC 2020 ACTUAL

FERC Account	Cost Centers	Labor	Other	Total
500	110016	15,959.42	30,089.86	46,049.28
506	110017	25,643.16	6,264.57	31,907.73
510	110018	32,587.24	2,106.35	34,693.59
511	110267	39,333.13	61,359.03	100,692.16
512	110268	270,460.40	992,994.80	1,263,455.20
513	110269	57,807.44	33,505.44	91,312.88
514	110270	19,092.66	14,257.18	33,349.84
500	110271	173,675.43	4,534.58	178,210.01
510	110272	94,382.71	2,904.83	97,287.54
501	110273	332,207.54	193,648.74	525,856.28
501	110273	0.00	(166,916.05)	(166,916.05)
502	110274	439,159.72	65,206.58	504,366.30
505	110275	205,891.53	2,743.39	208,634.92
506	110276	14,336.74	87,103.72	101,440.46
502	110714	0.00	0.00	0.00
512	110715	48,304.91	0.00	48,304.91
511	110842	0.00	0.00	0.00
505	110850	0.00	0.00	0.00
511	110864	2,210.03	0.00	2,210.03
513	110865	7,703.53	0.00	7,703.53
514	110866	4,925.20	0.00	4,925.20
502	140016	0.00	0.00	0.00
501	140745	0.00	0.00	0.00
501	140921	0.00	0.00	0.00
500	111635	0.00	0.00	0.00
510	111636	0.00	0.00	0.00
500	111680	3,415.20	12.37	3,427.57
500	111694	0.00	0.00	0.00
500	122346	41.03	52.83	93.86
510	122347	82.07	105.66	187.73
500	180036	4,107.27	110.67	4,217.94
510	180037	4,062.64	110.05	4,172.69
501 Aux Fuel		0.00	64,566.65	64,566.65
	TOTAL	$1,795,389.00	$1,394,761.25	$3,190,150.25

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
DEC 2020 ACTUAL

Campbell 3 GO - E&S - Production		549,522.97
MPPA OWNERSHIP %		4.80%
MPPA - GO E&S SHARE		$26,377.10
BILL MPPA		**$26,377.10**
	5000-0000-001-02	**13,188.55**
	5060-0000-001-02	**$13,188.55**
		26,377.10

GO E&S Labor =	$288,828.11	4.80%	$13,863.75

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	27,444.77			27,444.77	
Sys Prot	122258	1,455.68	99	1	1,454.30	
BTS-Stm Exp	180250	262,681.59	23	77	58,882.38	
Fossil Train	180223	44,418.67	77	23	33,892.97	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	156,462.00			156,462.00	
Security	141065	57,060.26	19	81	10,691.69	
		549,522.97			288,828.11	

Schedule III

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Employee Pension & Benefits
DEC 2020 ACTUAL

Production Labor (Schedule I)		$1,795,389.00
E&S Labor (Schedule II)		$288,828.11
Total Labor		$2,084,217.11
Pension & Benefits Loading Rate	x	2.60%
Penison & Benefits Expense		$54,189.64
MPPA OWNERSHIP %		4.80%
MPPA SHARE		$2,601.10

Schedule IV

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Payroll Taxes
DEC 2020 ACTUAL

Production Labor (Schedule I)		$1,795,389.00
E&S Labor (Schedule II)		$288,828.11
Total Labor		$2,084,217.11
Payroll Tax Loading Rate	x	7.32%
Payroll Tax		$152,564.69
MPPA OWNERSHIP %		4.80%
MPPA SHARE		$7,323.11

Schedule V

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Administrative and General Expenses
DEC 2020 ACTUAL

Production Expense	
Schedule I	$3,190,150.25
Less: A/C 501	($423,506.88)
	$2,766,643.37
GO Engineering & Supervision	
Schedule II	$549,522.97
Total	$3,316,166.34
A&G %	10.00%
Allocated A&G Expense	$331,616.63
MPPA OWNERSHIP %	4.80%
MPPA SHARE	$15,917.60

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
DEC 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**4,186.33**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**1,432.58**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**4,488.76**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**1,161.98**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**1,607.68**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**127.34**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**95.51**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**2,053.37**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**31.84**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**732.21**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		15,917.60	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$331,617		
Indirect Pen & Ben =	$331,617	0.80%	$2,653
A & G Salaries =	$331,617	26.30%	$87,215

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: 9320050003
INVOICE DATE: 1/26/21

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
JAN 2021	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF DEC 2020	$63,126.27	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF DEC 2020	$1,512.75	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF DEC 2020	0.00	

PAYMENT DUE BY 2/15/21 AMOUNT DUE $64,639.02

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 2/15/21

INVOICE STATEMENT NO: 9320050003

MICHIGAN PUBLIC POWER AGENCY

1/26/21

CONSUMERS ENERGY COMPANY
MPPA'S CONSTRUCTION COSTS
CAMPBELL #3
2020

MONTH CHARGES INCURRED	BILLING DATE	INVOICE #	$ AMOUNT	YTD $ AMOUNT
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MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319929125
INVOICE DATE: 1/7/21

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
JAN 2021	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR DEC 2020 REFERENCE EXHIBIT I	$403,080.64

PAYMENT DUE BY 1/20/21 AMOUNT DUE $403,080.64

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 1/20/21

INVOICE STATEMENT NO: 9319929125
0
1/7/21

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

DECEMBER 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,468
ADJUSTMENTS	0
WESTERN BURN:	(10,274)
EASTERN BURN:	(642)

ACTUAL COST:

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FUEL COSTS - WESTERN	$374,343.48
HANDLING COST - WESTERN	8,011.97
LIME CHARGES	12,247.19
UREA CHARGES	4,374.94
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	60,725
PRICE PER GALLON	$1.3327
% OF TOTAL BURN:	5.07%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

DECEMBER 2020 ACTUAL

(WET TONS)

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ADJUSTMENTS	0
BURN	(10,916)
ENDING BALANCE	2,552
CONTRACTUAL BALANCE	13,482
DECEMBER RECEIPTS	10,930

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

DECEMBER 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$374,343.48	
HANDLING			$8,011.97	
LIME CHARGES			12,247.19	
UREA CHARGES			4,374.94	
ACT. CARB.			-	
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	AUX GEN FUEL COST (EXHIBIT IIA)			$4,103.06
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1510-0000-000-02	5011-0000-001-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

DECEMBER 2020 ACTUAL

FUEL OIL USED IN GENERATION	60,725	GALS
PRICE PER GALLON	$1.3327	
TOTAL	$80,928.21	
MPPA % OF BURN	0.0507	
MPPA AUXILIARY FUEL COST	$4,103.06	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319951783
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FOR INQUIRIES CALL:
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DATE	DOC #	DESCRIPTION	CHARGES
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PAYMENT DUE BY 1/20/21

AMOUNT DUE $205,346.13

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CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 1/20/21

INVOICE STATEMENT NO: 9319951783

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
DEC 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$153,127.21	See Sched I
II	Gen Office Eng & Suprv - Allocation	$26,377.10	See Sched II
III	Employee Benefits	$2,601.10	**9260-0000-001-02**
IV	Payroll Taxes	$7,323.11	**4083-0000-001-02**
V	Admin & General Expenses	$15,917.60	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$205,346.13	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
DEC 2020 ACTUAL

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**11,135.94**	$197,198.35	$34,800.31	$231,998.66
501	**5011-0000-001-02**	**20,328.33**	$332,207.54	$91,299.34	$423,506.88
502	**5020-0000-001-02**	**24,209.58**	$439,159.72	$65,206.58	$504,366.30
505	**5050-0000-001-02**	**10,014.48**	$205,891.53	$2,743.39	$208,634.92
506	**5060-0000-001-02**	**6,400.71**	$39,979.90	$93,368.29	$133,348.19
510	**5100-0000-001-02**	**6,544.39**	$131,114.66	$5,226.89	$136,341.55
511	**5110-0000-001-02**	**4,939.31**	$41,543.16	$61,359.03	$102,902.19
512	**5120-0000-001-02**	**62,964.49**	$318,765.31	$992,994.80	$1,311,760.11
513	**5130-0000-001-02**	**4,752.79**	$65,510.97	$33,505.44	$99,016.41
514	**5140-0000-001-02**	**1,837.19**	$24,017.86	$14,257.18	$38,275.04
Total		**153,127.21**	$1,795,389.00	$1,394,761.25	$3,190,150.25
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$86,178.67	$66,948.54	$153,127.21

Schedule I-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Production Expenses
DEC 2020 ACTUAL

FERC Account	Cost Centers	Labor	Other	Total
500	110016	15,959.42	30,089.86	46,049.28
506	110017	25,643.16	6,264.57	31,907.73
510	110018	32,587.24	2,106.35	34,693.59
511	110267	39,333.13	61,359.03	100,692.16
512	110268	270,460.40	992,994.80	1,263,455.20
513	110269	57,807.44	33,505.44	91,312.88
514	110270	19,092.66	14,257.18	33,349.84
500	110271	173,675.43	4,534.58	178,210.01
510	110272	94,382.71	2,904.83	97,287.54
501	110273	332,207.54	193,648.74	525,856.28
501	110273	0.00	(166,916.05)	(166,916.05)
502	110274	439,159.72	65,206.58	504,366.30
505	110275	205,891.53	2,743.39	208,634.92
506	110276	14,336.74	87,103.72	101,440.46
502	110714	0.00	0.00	0.00
512	110715	48,304.91	0.00	48,304.91
511	110842	0.00	0.00	0.00
505	110850	0.00	0.00	0.00
511	110864	2,210.03	0.00	2,210.03
513	110865	7,703.53	0.00	7,703.53
514	110866	4,925.20	0.00	4,925.20
502	140016	0.00	0.00	0.00
501	140745	0.00	0.00	0.00
501	140921	0.00	0.00	0.00
500	111635	0.00	0.00	0.00
510	111636	0.00	0.00	0.00
500	111680	3,415.20	12.37	3,427.57
500	111694	0.00	0.00	0.00
500	122346	41.03	52.83	93.86
510	122347	82.07	105.66	187.73
500	180036	4,107.27	110.67	4,217.94
510	180037	4,062.64	110.05	4,172.69
501 Aux Fuel		0.00	64,566.65	64,566.65
	TOTAL	$1,795,389.00	$1,394,761.25	$3,190,150.25

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
DEC 2020 ACTUAL

Campbell 3 GO - E&S - Production		549,522.97	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$26,377.10	
BILL MPPA		**$26,377.10**	
5000-0000-001-02		**13,188.55**	
5060-0000-001-02		**$13,188.55**	
		26,377.10	
GO E&S Labor =	$288,828.11	4.80%	$13,863.75

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	27,444.77			27,444.77	
Sys Prot	122258	1,455.68	99	1	1,454.30	
BTS-Stm Exp	180250	262,681.59	23	77	58,882.38	
Fossil Train	180223	44,418.67	77	23	33,892.97	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	156,462.00			156,462.00	
Security	141065	57,060.26	19	81	10,691.69	
		549,522.97			288,828.11	

Schedule III

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Employee Pension & Benefits
DEC 2020 ACTUAL

Production Labor (Schedule I)	$1,795,389.00
E&S Labor (Schedule II)	$288,828.11
Total Labor	$2,084,217.11
Pension & Benefits Loading Rate	x 2.60%
Penison & Benefits Expense	$54,189.64
MPPA OWNERSHIP %	4.80%
MPPA SHARE	$2,601.10

Schedule IV

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Payroll Taxes
DEC 2020 ACTUAL

Production Labor (Schedule I)		$1,795,389.00
E&S Labor (Schedule II)		$288,828.11
Total Labor		$2,084,217.11
Payroll Tax Loading Rate	x	7.32%
Payroll Tax		$152,564.69
MPPA OWNERSHIP %		4.80%
MPPA SHARE		$7,323.11

Schedule V

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Administrative and General Expenses
DEC 2020 ACTUAL

Production Expense	
Schedule I	$3,190,150.25
Less: A/C 501	($423,506.88)
	$2,766,643.37
GO Engineering & Supervision	
Schedule II	$549,522.97
Total	$3,316,166.34
A&G %	10.00%
Allocated A&G Expense	$331,616.63
MPPA OWNERSHIP %	4.80%
MPPA SHARE	$15,917.60

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
DEC 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**4,186.33**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**1,432.58**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**4,488.76**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**1,161.98**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**1,607.68**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**127.34**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**95.51**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**2,053.37**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**31.84**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**732.21**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		15,917.60	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$331,617		
Indirect Pen & Ben =	$331,617	0.80%	$2,653
A & G Salaries =	$331,617	26.30%	$87,215

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9317885972**
INVOICE DATE: 3/18/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
MAR 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF FEB 2020	$56,386.24	**1066-2000-000-(**
	RETIREMENT EXPENDITURES DURING THE MONTH OF FEB 2020	$374.20	**1086-2000-001-(**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF FEB 2020	0.00	

PAYMENT DUE BY 4/15/20 AMOUNT DUE $56,760.44

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 4/15/20

INVOICE STATEMENT NO: 9317885972

MICHIGAN PUBLIC POWER AGENCY

3/18/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF FEBRUARY 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846	45.59	2.19
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556	81.17	3.90
24777421	25065937	1,987.69	95.41
24851767	25065938	2,003.08	96.15
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	3,246.42	155.83
29090639	29303622		0.00
29255064	29255064	35,375.64	1,698.03
29342833	29649993	6,884.07	330.44
29648629	29952931	3,743.58	179.69
29344915	30136463	14,724.43	706.77
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	40,288.85	1,933.86
30461542	31464878		0.00
31593775	31903546	239,363.60	11,489.45
31594191	31903557	41,771.69	2,005.04
31672277	31903077	249,317.62	11,967.25
31732508	31903079		0.00
31768429	32014366	41,675.35	2,000.42
31768432	32014370	6,004.47	288.21
31672365	32061343	5,297.27	254.27
31594199	32182462	33,178.98	1,592.59
31769040	32182464	18,278.74	877.38
31769228	32547749	3,286.28	157.74
31630779	32686481	1,297.31	62.27
32762652	33432977		0.00
33365304	33900652	463.09	22.23
33470359	33947104	71,754.62	3,444.22
29535933	33947106		0.00
32762651	34070925	2,947.56	141.48
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	155,007.99	7,440.38
34066657	34484358		0.00
34275673	34640501	1,675.86	80.44
34498210	34640502	23,806.08	1,142.69
34646163	34646163	535.67	25.71
34275231	34769326	89,839.57	4,312.30
34536864	34769328	5,128.56	246.17
34616096	34770035	2,930.55	140.67
34066741	34929637		0.00
34763474	34929801	(822.06)	(39.46)
34763477	34947989	26,344.70	1,264.55
34763479	34947990	168.66	8.10
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	3,070.53	147.39
34686388	35084577		0.00
35117725	35247545	6,489.15	311.48
34238934	35250267	134.76	6.47
35385384	35404444		0.00

34756522	35418570		0.00
34815514	35418571	(41.74)	(2.00)
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	3,251.92	156.09
35588963	35588964		0.00
35072889	35607300	13,565.57	651.15
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596	(14,838.25)	(712.24)
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041		0.00
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	6,830.53	327.87
35988062	36180715	28,618.24	1,373.68
TOTAL		**1,174,713.39**	**56,386.24**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950	343.73	16.50
29255064	29255064	3,850.42	184.82
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557	1,291.46	61.99
31672365	32061343	261.04	12.53
31630779	32686481		
29535933	33947106	1,915.19	91.93
33377496	34383018		
34646163	34646163	133.96	6.43
34536864	34769328		
TOTAL		**7,795.80**	**374.20**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9317751459
INVOICE DATE: 3/4/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
MAR 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR FEB 2020 REFERENCE EXHIBIT I	$530,510.47

PAYMENT DUE BY 3/20/20 AMOUNT DUE $530,510.47

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 3/20/20

INVOICE STATEMENT NO: 9317751459
0
3/4/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

FEBRUARY 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(14,961)

ACTUAL COST:

WESTERN RECEIPTS	14,961
FUEL COSTS - WESTERN	$542,321.29
HANDLING COST - WESTERN	8,273.43
LIME CHARGES	3,676.92
UREA CHARGES	2,180.50
ACTIVATED CARBON	(29,231.34)

AUX GEN FUEL COSTS:

FUEL OIL USED:	28,987
PRICE PER GALLON	$1.9737
% OF TOTAL BURN:	5.75%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

FEBRUARY 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(14,961)
ENDING BALANCE	(1,479)
CONTRACTUAL BALANCE	13,482
FEBRUARY RECEIPTS	14,961

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

FEBRUARY 2020 ACTUAL

ACTUAL FUEL COST

		WESTERN	
FUEL		$542,321.29	
HANDLING		$8,273.43	
LIME CHARGES		3,676.92	
UREA CHARGES		2,180.50	
ACT. CARB.		(29,231.34)	
TONS (WET)	14,961		
UNIT PRICE	$35		
TOTAL		$527,220.80	$527,220.80
AUX GEN FUEL COST (EXHIBIT IIA)			$3,289.67
TOTAL INVOICE TO MPPA			$530,510.47

Fuel	Fuel Hdlg	
$545,610.96	($15,100.49)	$530,510.47
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

FEBRUARY 2020 ACTUAL

FUEL OIL USED IN GENERATION	28,987	GALS
PRICE PER GALLON	$1.9737	
TOTAL	$57,211.64	
MPPA % OF BURN	0.0575	
MPPA AUXILIARY FUEL COST	$3,289.67	

FUEL INVENTORY AND EXPENSE REPORT
FEBRUARY 2020

CAMPBELL 3 -- MPPA WESTERN 03-Mar-20

		WET TONS	UNIT PRICE	AMOUNT	Accounting Distribution	Debit	Credit
BALANCE FORWARD		13,482.00	48.28	650,907.73	G/L Acct 1697760	(29,231.34)	
Adjustments- Prior Transfer		0.00		0.00	G/L Acct 4616000		(29,231.34)
Balance - Beginning Month		13,482.00	48.280	650,907.73	Order 6608175 (Act. Carb)		
Prior Month Burn Adjustment				(7,453.37)	G/L Acct 1697760	2,180.50	
					G/L Acct 4616000		2,180.50
					Order 6607947 (Urea)		
Fuel Receipts-Current Month		14,961.00	36.249	542,321.29	G/L Acct 1697760	3,676.92	
					G/L Acct 4616000		3,676.92
					Order 6608172 (Lime)		
					G/L Acct 1697760	542,321.29	
Subtotal		28,443.00	41.690	1,185,775.64	Inv Acct 1622000		542,321.29
Fuel Expense							
Fuel Burned					G/L Acct 1697760	8,273.43	
Fuel Burned		14,961.00	37.860	566,423.46	G/L Acct 5101700		
Total Expense		14,961.00		566,423.46	Cst Ctr 110909		8,273.43
BALANCE FORWARD		13,482.00	45.939	619,352.18		527,220.80	527,220.80

Burn Adjustment Calculation:	Tons Burned	611B Rate	611 Total	Fuelworx Rate	Adjusted Total	Adjustment
January 2020	16,098.00	$ 38.971	$ 627,355.16	$ 39.434	$ 634,808.53	$ (7,453.37)

FUEL INVENTORY AND EXPENSE REPORT
FEBRUARY 2020

CAMPBELL 3 -- WESTERN

03-Mar-20

		WET TONS	UNIT PRICE	AMOUNT	Accounting Distribution	Debit	Credit
BALANCE FORWARD		839,439.67	38.600	32,402,561.09			
Prior Month Receipt Adjustment		0.00		0.00			
Balance - Beginning Month		839,439.67	38.600	32,402,561.09			
					G/L Acct 4604000		
Prior Month Burn Adjustment		**0.00**		**10,388.33**	Int Order 6607858		789,456.72
					Inv Acct 1622000	789,456.72	
RECEIPTS							
Estimate to Actual Receipts				0.00			
Fuel Receipts-Current Month		412,848.88	36.249	14,965,399.06	G/L Acct 4604000		
					Int Order 6607858		10,388.33
					Inv Acct 1622000	10,388.33	
Transfers Out - MPPA		(14,961.00)	36.249	(542,321.29)			
- Wolverine		(5,590.00)	36.249	(202,631.91)			
Subtotal		1,231,737.55	37.860	46,633,395.28			
Fuel Expense					G/L Acct 4604000		
Fuel Burned - Camp 1 & 2		81,674.40		3,141,753.29	Int Order 6607851	3,141,753.29	
Fuel Burned - Camp #3		239,276.20		9,112,129.82	Int Order 6607858	9,901,586.54	
Total Expense		320,950.60		12,253,883.11	Inv Acct 1622000		13,043,339.83
BALANCE FORWARD		910,786.95	37.747	34,379,512.17		13,843,184.88	13,843,184.88

CAMPBELL #3 FUEL OIL
February 2020

GENERATING GALLONS	NON-GENERATING GALLONS	CURRENT MONTH BALANCE S/A PRICE	% OF DRY TONS USED MPPA	% OF DRY TONS USED WPSC	GEN FUEL OIL	
a	b	c	d	e	f	
					a x c x d x e	
					$3,289.67	MPPA
					$1,292.98	WPSC
28,987	0	1.9737	0.0575	0.0226		
			0.057513949	0.022646526	$4,582.65	

MPPA & WPSC GALLONS	MPPA & WPSC NON GEN GALLS	MPPA & WPSC NON-GEN $'s	Non- GEN FUEL OIL	
			g	
			b x c x e	
2,322	0	$0.00	0.00	WPSC

MPPA & WPSC
TO GALLONS
2,322

		DEBIT	CREDIT
	1697700	$4,582.65	
	1697750	$0.00	
Int Ord	6607859		$4,582.65
	4608000		

CE SHARE	
26,665	0

Account Reconciliation

1697700		
February	$4,582.65	
January	$1,151.97	WPSC Only
	$5,734.62	

1697750		
February	$0.00	
January	$0.00	WPSC Only
	$0.00	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9317817492
INVOICE DATE: 3/9/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
MAR 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF FEB 2020	$109,448.97

PAYMENT DUE BY 3/20/20

AMOUNT DUE $109,448.97

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 3/20/20

INVOICE STATEMENT NO: 9317817492

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
FEB 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$80,286.45	See Sched I
II	Gen Office Eng & Suprv - Allocation	$11,037.86	See Sched II
III	Employee Benefits	$2,590.97	**9260-0000-001-02**
IV	Payroll Taxes	$5,237.96	**4083-0000-001-02**
V	Admin & General Expenses	$10,295.73	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$109,448.97	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
FEB 2020 ACTUAL

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**10,254.09**	$200,628.03	$12,998.78	$213,626.81
501	**5011-0000-001-02**	**6,933.12**	$268,016.89	($123,576.90)	$144,439.99
502	**5020-0000-001-02**	**17,545.62**	$343,131.24	$22,402.47	$365,533.71
505	**5050-0000-001-02**	**7,269.59**	$150,280.75	$1,169.02	$151,449.77
506	**5060-0000-001-02**	**3,569.40**	$38,765.45	$35,597.05	$74,362.50
510	**5100-0000-001-02**	**5,551.79**	$105,438.89	$10,223.46	$115,662.35
511	**5110-0000-001-02**	**2,250.44**	$29,098.68	$17,785.45	$46,884.13
512	**5120-0000-001-02**	**23,922.21**	$188,566.66	$309,812.70	$498,379.36
513	**5130-0000-001-02**	**1,000.71**	$22,984.07	($2,135.86)	$20,848.21
514	**5140-0000-001-02**	**1,989.48**	$25,032.37	$16,415.25	$41,447.62
Total		80,286.45	$1,371,943.03	$300,691.42	$1,672,634.45
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$65,853.27	$14,433.19	$80,286.45

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
FEB 2020 ACTUAL

Campbell 3 GO - E&S - Production		229,955.41	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$11,037.86	
BILL MPPA		**$11,037.86**	
	5000-0000-001-02	**5,518.93**	
	5060-0000-001-02	**$5,518.93**	
		11,037.86	
GO E&S Labor =	$86,934.83	4.80%	$4,172.87

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	3,245.06	96	4	3,099.04	
BTS-Stm Exp	180250	154,442.78	28	72	42,479.46	
Fossil Train	180223	42,113.78	80	20	33,757.54	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	30,153.79	25	75	7,598.79	
		229,955.41			86,934.83	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
FEB 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,368.02**	43,115,738.00	(16,299,544.00)	190,888.00	$27,007,082	23.00%
921	**9210-0000-001-02**	**978.09**	13,886,497.00	(2,939,016.00)	331,410.00	$11,278,891	9.50%
922	**9220-0000-001-02**	-	(19,238,560.00)	19,238,560.00		$0	0.00%
923	**9230-0000-001-02**	**2,769.55**	31,539,992.00	0.00	269,122.00	$31,809,114	26.90%
924	**9240-0000-001-02**	**761.88**	672,467.00	8,003,941.00	85,107.00	$8,761,515	7.40%
925	**9250-0000-001-02**	**1,029.57**	11,667,830.00	0.00	168,488.00	$11,836,318	10.00%
926	**9260-0000-001-02**	**113.25**	8,610,967.00	(8,004,501.00)	696,592.00	$1,303,058	1.10%
928	**9280-0000-001-02**	**51.48**	646,798.00	0.00	2,303.00	$649,101	0.50%
930	**9300-0000-001-02**	**1,709.09**	19,512,040.00	0.00	71,369.00	$19,583,409	16.60%
931	**9310-0000-001-02**	-	(37,435.00)	0.00	3,951.00	($33,484)	0.00%
935	**9350-0000-001-02**	**514.80**	5,887,963.00	0.00	61,526.00	$5,949,489	5.00%
		10,295.73	$116,264,297	($560)	$1,880,756	$118,144,493	100.0%

Indirect Pension & Benefits % =		1.10%	
Allocated A & G =	$214,494		
Indirect Pen & Ben =	$214,494	1.10%	$2,359
A & G Salaries =	$214,494	23.00%	$49,334

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9318133206**
INVOICE DATE: 4/23/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION		CHARGES	
APR 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF	MAR 2020	$24,036.38	**1066-2000-000-(**
	RETIREMENT EXPENDITURES DURING THE MONTH OF	MAR 2020	$304.44	**1086-2000-001-(**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF	MAR 2020	0.00	

PAYMENT DUE BY 5/15/20 AMOUNT DUE $24,340.82

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 5/15/20

INVOICE STATEMENT NO: 9318133206

MICHIGAN PUBLIC POWER AGENCY

4/23/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF MARCH 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044	(9.00)	(0.43)
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556	196.60	9.44
24777421	25065937	4,256.27	204.30
24851767	25065938	934.91	44.88
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	2,799.59	134.38
29090639	29303622		0.00
29255064	29255064	58,651.76	2,815.28
29342833	29649993	8,172.73	392.29
29648629	29952931	(43,087.40)	(2,068.20)
29344915	30136463	353.34	16.96
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	3,945.89	189.40
30461542	31464878		0.00
31593775	31903546	6,613.47	317.45
31594191	31903557	9,093.88	436.51
31672277	31903077	32,322.55	1,551.48
31732508	31903079		0.00
31768429	32014366	18,546.34	890.22
31768432	32014370	13,693.96	657.31
31672365	32061343	5,810.03	278.88
31594199	32182462	1,157.36	55.55
31769040	32182464	7,616.61	365.60
31769228	32547749	164,685.49	7,904.90
31630779	32686481	(46,741.38)	(2,243.59)
32762652	33432977		0.00
33365304	33900652	794.99	38.16
33470359	33947104	33,015.06	1,584.72
29535933	33947106		0.00
32762651	34070925	(2,383.22)	(114.39)
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	75,205.16	3,609.85
34066657	34484358		0.00
34275673	34640501	1,117.79	53.65
34498210	34640502	9,325.17	447.61
34646163	34646163	3,170.15	152.17
34275231	34769326	(61,636.63)	(2,958.56)
34536864	34769328	9,328.18	447.75
34616096	34770035	4,989.73	239.51
34066741	34929637		0.00
34763474	34929801	650.51	31.22
34763477	34947989	104,934.85	5,036.87
34763479	34947990	650.51	31.22
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	7,502.73	360.13
34686388	35084577		0.00
35117725	35247545	6,547.03	314.26
34238934	35250267		0.00
35385384	35404444		0.00

34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	10,161.31	487.74
35588963	35588964		0.00
35072889	35607300	1,108.32	53.20
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35098589	35637415	2,416.29	115.98
33916264	35702594		0.00
34923179	35702596	(2,277.06)	(109.30)
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041	16,191.77	777.20
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	3,816.21	183.18
35988062	36180715	19,804.05	950.59
35420948	36271040	1,999.53	95.98
36095379	36271041	26.44	1.27
36096196	36271042	5,284.54	253.73
TOTAL		**500,756.41**	**24,036.38**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950	(1,182.41)	(56.76)
29255064	29255064	6,450.21	309.61
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557	93.13	4.47
31672365	32061343	265.00	12.72
31630779	32686481		
29535933	33947106		
33377496	34383018		
34646163	34646163	716.67	34.40
34536864	34769328		
TOTAL		**6,342.60**	**304.44**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9318011486
INVOICE DATE: 4/6/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
APR 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR MAR 2020 REFERENCE EXHIBIT I	$645,260.73

PAYMENT DUE BY 4/20/20 AMOUNT DUE $645,260.73

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 4/20/20

INVOICE STATEMENT NO: 9318011486
0
4/6/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

MARCH 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(15,990)

ACTUAL COST:

WESTERN RECEIPTS	15,990
FUEL COSTS - WESTERN	$618,573.15
HANDLING COST - WESTERN	13,959.27
LIME CHARGES	4,986.15
UREA CHARGES	2,117.54
ACTIVATED CARBON	1,922.89

AUX GEN FUEL COSTS:

FUEL OIL USED:	35,887
PRICE PER GALLON	$1.6347
% OF TOTAL BURN:	6.31%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

MARCH 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(15,990)
ENDING BALANCE	(2,508)
CONTRACTUAL BALANCE	13,482
MARCH RECEIPTS	15,990

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

MARCH 2020 ACTUAL

ACTUAL FUEL COST

		WESTERN	
FUEL		$618,573.15	
HANDLING		$13,959.27	
LIME CHARGES		4,986.15	
UREA CHARGES		2,117.54	
ACT. CARB.		1,922.89	
TONS (WET)	15,990		
UNIT PRICE	$40		
TOTAL		$641,559.00	$641,559.00
AUX GEN FUEL COST (EXHIBIT IIA)			$3,701.73
TOTAL INVOICE TO MPPA			$645,260.73

Fuel	Fuel Hdlg	
$622,274.88	$22,985.85	$645,260.73
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

MARCH 2020 ACTUAL

FUEL OIL USED IN GENERATION	35,887	GALS
PRICE PER GALLON	$1.6347	
TOTAL	$58,664.48	
MPPA % OF BURN	0.0631	
MPPA AUXILIARY FUEL COST	$3,701.73	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	**$645,260.73**		
1697760		**$641,559.00**	coal
1697700		**$3,701.73**	fuel oil
1697700			
TOTAL	$645,260.73	$645,260.73	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9318013396
INVOICE DATE: 4/7/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
APR 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF MAR 2020	$121,240.54

PAYMENT DUE BY 4/20/20

AMOUNT DUE $121,240.54

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 4/20/20

INVOICE STATEMENT NO: 9318013396

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
MAR 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$85,543.58	See Sched I
II	Gen Office Eng & Suprv - Allocation	$14,954.56	See Sched II
III	Employee Benefits	$2,820.62	**9260-0000-001-02**
IV	Payroll Taxes	$5,702.22	**4083-0000-001-02**
V	Admin & General Expenses	$12,219.57	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$121,240.54	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
MAR 2020 **ACTUAL**

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**11,782.17**	$210,776.63	$34,685.22	$245,461.85
501	**5011-0000-001-02**	**337.71**	$264,282.79	($257,247.24)	$7,035.55
502	**5020-0000-001-02**	**26,127.61**	$355,577.05	$188,748.06	$544,325.11
505	**5050-0000-001-02**	**7,415.28**	$153,547.19	$937.79	$154,484.98
506	**5060-0000-001-02**	**3,262.82**	$36,424.57	$31,550.76	$67,975.33
510	**5100-0000-001-02**	**6,115.77**	$113,846.81	$13,565.04	$127,411.85
511	**5110-0000-001-02**	**3,473.23**	$30,586.63	$41,772.36	$72,358.99
512	**5120-0000-001-02**	**25,150.36**	$218,125.62	$305,840.16	$523,965.78
513	**5130-0000-001-02**	**74.21**	$33,139.23	($31,593.09)	$1,546.14
514	**5140-0000-001-02**	**1,804.42**	$19,188.20	$18,404.15	$37,592.35
Total		85,543.58	$1,435,494.72	$346,663.21	$1,782,157.93
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$68,903.75	$16,639.83	$85,543.58

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
MAR 2020 ACTUAL

Campbell 3 GO - E&S - Production		311,553.25	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$14,954.56	
BILL MPPA		**$14,954.56**	
	5000-0000-001-02	**7,477.28**	
	5060-0000-001-02	**$7,477.28**	
		14,954.56	
GO E&S Labor =	$152,690.60	4.80%	$7,329.15

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	9,714.31			9,714.31	
Sys Prot	122258	3,136.61	99	1	3,103.52	
BTS-Stm Exp	180250	162,727.43	24	76	39,275.58	
Fossil Train	180223	42,734.93	80	20	34,210.64	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	58,694.00	100	0	58,694.00	
Security	141065	34,545.97	22	78	7,692.55	
		311,553.25			152,690.60	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
MAR 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,810.50**	43,115,738.00	(16,299,544.00)	190,888.00	$27,007,082	23.00%
921	**9210-0000-001-02**	**1,160.86**	13,886,497.00	(2,939,016.00)	331,410.00	$11,278,891	9.50%
922	**9220-0000-001-02**	-	(19,238,560.00)	19,238,560.00		$0	0.00%
923	**9230-0000-001-02**	**3,287.06**	31,539,992.00	0.00	269,122.00	$31,809,114	26.90%
924	**9240-0000-001-02**	**904.25**	672,467.00	8,003,941.00	85,107.00	$8,761,515	7.40%
925	**9250-0000-001-02**	**1,221.96**	11,667,830.00	0.00	168,488.00	$11,836,318	10.00%
926	**9260-0000-001-02**	**134.42**	8,610,967.00	(8,004,501.00)	696,592.00	$1,303,058	1.10%
928	**9280-0000-001-02**	**61.10**	646,798.00	0.00	2,303.00	$649,101	0.50%
930	**9300-0000-001-02**	**2,028.45**	19,512,040.00	0.00	71,369.00	$19,583,409	16.60%
931	**9310-0000-001-02**	-	(37,435.00)	0.00	3,951.00	($33,484)	0.00%
935	**9350-0000-001-02**	**610.98**	5,887,963.00	0.00	61,526.00	$5,949,489	5.00%
		12,219.58	$116,264,297	($560)	$1,880,756	$118,144,493	100.0%

Indirect Pension & Benefits % =		1.10%	
Allocated A & G =	$254,574		
Indirect Pen & Ben =	$254,574	1.10%	$2,800
A & G Salaries =	$254,574	23.00%	$58,552

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9318383860**
INVOICE DATE: 5/27/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION		CHARGES	
MAY 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF	APR 2020	$13,815.11	**1066-2000-000-(**
	RETIREMENT EXPENDITURES DURING THE MONTH OF	APR 2020	$663.10	**1086-2000-001-(**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF	APR 2020	0.00	

PAYMENT DUE BY 6/15/20 AMOUNT DUE $14,478.21

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 6/15/20

INVOICE STATEMENT NO: 9318383860

MICHIGAN PUBLIC POWER AGENCY

5/27/20

CONSUMERS ENERGY
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF APRIL 2020

Schedule II

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044	9.14	0.44
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301	3,484.79	167.27
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556	48.89	2.35
24777421	25065937	2,073.40	99.52
24851767	25065938	526.14	25.25
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	(1,890.93)	(90.76)
29090639	29303622		0.00
29255064	29255064	4,073.83	195.54
29342833	29649993	14,112.49	677.40
29648629	29952931	10,755.15	516.25
29342487	30136462	6,429.25	308.60
29344915	30136463	353.36	16.96
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	1,821.38	87.43
30461542	31464878		0.00
31593775	31903546	6,608.47	317.21
31594191	31903557	2,643.48	126.89
31672277	31903077	(15,845.64)	(760.59)
31732508	31903079	3,148.65	151.14
31768429	32014366	25,924.42	1,244.37
31768432	32014370	2,331.26	111.90
31672365	32061343	3,451.73	165.68
31594199	32182462	12,749.73	611.99
31769040	32182464	2,036.45	97.75
31769228	32547749	4,645.05	222.96
32080550	32547750	(127.54)	(6.12)
31630779	32686481	13,188.41	633.04
32762652	33432977		0.00
33365304	33900652		0.00
33470359	33947104	33,276.98	1,597.30
29535933	33947106		0.00
32762651	34070925	693.57	33.29
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	4,156.70	199.52
34066657	34484358		0.00
34275673	34640501	852.85	40.94
34498210	34640502	4,596.09	220.61
34646163	34646163	817.84	39.26
34275231	34769326	15,488.38	743.44
34536864	34769328	1,362.33	65.39
34616096	34770035	2,575.26	123.61
34066741	34929637		0.00
34763474	34929801	626.43	30.07
34763477	34947989	(11,466.71)	(550.40)
34763479	34947990	626.43	30.07
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	11,547.25	554.27
34686388	35084577		0.00

35117725	35247545	1,577.92	75.74
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	6,357.61	305.17
35588963	35588964		0.00
35072889	35607300	456.49	21.91
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041		0.00
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	5,163.91	247.87
35988062	36180715		0.00
35988062	36221401	41,352.38	1,984.91
35420948	36271040	383.69	18.42
36095379	36271041		0.00
36096196	36271042	49,756.06	2,388.29
36204335	36383347	2,257.25	108.35
36308739	36383348	4,832.37	231.95
36047938	36383821	7,971.70	382.67
TOTAL		**287,814.14**	**13,815.11**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950	8,208.67	394.02
29255064	29255064	452.71	21.73
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557	110.00	5.28
31672365	32061343	124.17	5.96
31630779	32686481		
29535933	33947106	4,719.34	226.53
33377496	34383018		
34646163	34646163	199.58	9.58
34536864	34769328		
TOTAL		**13,814.47**	**663.10**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9318098390
INVOICE DATE: 5/6/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
MAY 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR APR 2020 REFERENCE EXHIBIT I	$550,688.95

PAYMENT DUE BY 5/20/20 AMOUNT DUE $550,688.95

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 5/20/20

INVOICE STATEMENT NO: 9318098390
0
5/6/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

APRIL 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(12,933)

ACTUAL COST:

WESTERN RECEIPTS	12,933
FUEL COSTS - WESTERN	$514,500.61
HANDLING COST - WESTERN	18,662.31
LIME CHARGES	5,452.67
UREA CHARGES	6,228.37
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	49,115
PRICE PER GALLON	$1.6347
% OF TOTAL BURN:	7.28%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

APRIL 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(12,933)
ENDING BALANCE	549
CONTRACTUAL BALANCE	13,482
APRIL RECEIPTS	12,933

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

APRIL 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$514,500.61	
HANDLING			$18,662.31	
LIME CHARGES			5,452.67	
UREA CHARGES			6,228.37	
ACT. CARB.			-	
TONS (WET)		12,933		
UNIT PRICE		$42		
	TOTAL		$544,843.96	$544,843.96
	AUX GEN FUEL COST (EXHIBIT IIA)			$5,844.99
	TOTAL INVOICE TO MPPA			$550,688.95

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

APRIL 2020 ACTUAL

FUEL OIL USED IN GENERATION	49,115	GALS
PRICE PER GALLON	$1.6347	
TOTAL	$80,288.29	
MPPA % OF BURN	0.0728	
MPPA AUXILIARY FUEL COST	$5,844.99	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	**$550,688.95**		
1697760		**$544,843.96**	coal
1697700		**$5,844.99**	fuel oil
1697700			
TOTAL	$550,688.95	$550,688.95	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9318210684
INVOICE DATE: 5/7/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
MAY 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF APR 2020	$183,543.89

PAYMENT DUE BY 5/20/20

AMOUNT DUE $183,543.89

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 5/20/20

INVOICE STATEMENT NO: 9318210684

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
APR 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$138,729.13	See Sched I
II	Gen Office Eng & Suprv - Allocation	$10,938.28	See Sched II
III	Employee Benefits	$5,054.47	**9260-0000-001-02**
IV	Payroll Taxes	$10,218.22	**4083-0000-001-02**
V	Admin & General Expenses	$18,603.79	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$183,543.89	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
APR 2020 **ACTUAL**

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**77,156.18**	$1,478,915.72	$128,504.71	$1,607,420.43
501	**5011-0000-001-02**	**(2,822.68)**	$243,379.77	($302,185.51)	($58,805.74)
502	**5020-0000-001-02**	**14,400.64**	$275,816.51	$24,196.80	$300,013.31
505	**5050-0000-001-02**	**5,944.71**	$123,117.03	$731.04	$123,848.07
506	**5060-0000-001-02**	**3,183.58**	$34,367.07	$31,957.51	$66,324.58
510	**5100-0000-001-02**	**15,427.64**	$302,765.16	$18,644.00	$321,409.16
511	**5110-0000-001-02**	**2,290.44**	$20,509.16	$27,208.43	$47,717.59
512	**5120-0000-001-02**	**17,841.53**	$211,502.75	$160,195.73	$371,698.48
513	**5130-0000-001-02**	**3,963.73**	$45,947.70	$36,630.05	$82,577.75
514	**5140-0000-001-02**	**1,343.35**	$20,002.97	$7,983.67	$27,986.64
Total		138,729.12	$2,756,323.84	$133,866.43	$2,890,190.27
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$132,303.54	$6,425.59	$138,729.13

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
APR 2020 ACTUAL

Campbell 3 GO - E&S - Production		227,880.81	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$10,938.28	
BILL MPPA		**$10,938.28**	
	5000-0000-001-02	**5,469.14**	
	5060-0000-001-02	**$5,469.14**	
		10,938.28	
GO E&S Labor =	$89,659.37	4.80%	$4,303.65

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,505.47	99	1	1,493.70	
BTS-Stm Exp	180250	160,510.06	28	72	45,596.77	
Fossil Train	180223	40,603.98	87	13	35,398.12	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	25,261.30	28	72	7,170.78	
		227,880.81			89,659.37	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
APR 2020 Actual

Account		Amount	Less	Billing CR Addbacks	Balance	% of Total
920 **9200-0000-001-02**	**4,278.87**	43,115,738.00	(16,299,544.00)	190,888.00	$27,007,082	23.00%
921 **9210-0000-001-02**	**1,767.36**	13,886,497.00	(2,939,016.00)	331,410.00	$11,278,891	9.50%
922 **9220-0000-001-02**	**-**	(19,238,560.00)	19,238,560.00		$0	0.00%
923 **9230-0000-001-02**	**5,004.42**	31,539,992.00	0.00	269,122.00	$31,809,114	26.90%
924 **9240-0000-001-02**	**1,376.68**	672,467.00	8,003,941.00	85,107.00	$8,761,515	7.40%
925 **9250-0000-001-02**	**1,860.38**	11,667,830.00	0.00	168,488.00	$11,836,318	10.00%
926 **9260-0000-001-02**	**204.64**	8,610,967.00	(8,004,501.00)	696,592.00	$1,303,058	1.10%
928 **9280-0000-001-02**	**93.02**	646,798.00	0.00	2,303.00	$649,101	0.50%
930 **9300-0000-001-02**	**3,088.23**	19,512,040.00	0.00	71,369.00	$19,583,409	16.60%
931 **9310-0000-001-02**	**-**	(37,435.00)	0.00	3,951.00	($33,484)	0.00%
935 **9350-0000-001-02**	**930.19**	5,887,963.00	0.00	61,526.00	$5,949,489	5.00%
	18,603.79	$116,264,297	($560)	$1,880,756	$118,144,493	100.0%

Indirect Pension & Benefits % =		1.10%	
Allocated A & G =	$387,579		
Indirect Pen & Ben =	$387,579	1.10%	$4,263
A & G Salaries =	$387,579	23.00%	$89,143

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9318554040**
INVOICE DATE: 6/18/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION		CHARGES	
JUNE 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF	MAY 2020	$39,850.04	**1066-2000-000-(**
	RETIREMENT EXPENDITURES DURING THE MONTH OF	MAY 2020	($121.26)	**1086-2000-001-(**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF	MAY 2020	0.00	

PAYMENT DUE BY 7/15/20

AMOUNT DUE $39,728.78

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 7/15/20

INVOICE STATEMENT NO: 9318554040

MICHIGAN PUBLIC POWER AGENCY

6/18/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF MAY 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301		0.00
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	1,311.22	62.94
24851767	25065938	89.00	4.27
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	69,472.91	3,334.70
29090639	29303622		0.00
29255064	29255064	2,456.92	117.93
29342833	29649993	10,136.81	486.57
29648629	29952931	3,533.03	169.59
29342487	30136462		0.00
29344915	30136463	445.00	21.36
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	10,488.63	503.45
30461542	31464878		0.00
31593775	31903546	12,548.10	602.31
31594191	31903557	886.21	42.54
31672277	31903077	9,055.56	434.67
31732508	31903079		0.00
31768429	32014366	7,994.72	383.75
31768432	32014370	2,466.32	118.38
31672365	32061343	422.71	20.29
31594199	32182462	4,358.03	209.19
31769040	32182464	4,795.97	230.21
31769228	32547749	7,819.40	375.33
32080550	32547750		0.00
31630779	32686481	3,165.73	151.96
32762652	33432977		0.00
31338989	33434098	(37.12)	(1.78)
33365304	33900652		0.00
33470359	33947104	12,359.32	593.25
29535933	33947106		0.00
32762651	34070925	422.78	20.29
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	2,685.54	128.91
34066657	34484358		0.00
34275673	34640501	666.66	32.00
34498210	34640502	3,051.64	146.48
34646163	34646163	679.82	32.63
34275231	34769326	12,894.96	618.96
34536864	34769328	62,890.16	3,018.73
34616096	34770035	6,539.99	313.92
34066741	34929637		0.00
34688256	34929638	15,229.54	731.02
34763474	34929801	1,008.44	48.41
34763477	34947989	3,645.70	174.99
34763479	34947990	1,008.44	48.41
34550414	34949236		0.00
34686197	34949843		0.00

34815508	35084575	83,010.54	3,984.51
34686388	35084577		0.00
35117725	35247545	1,235.45	59.30
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	6,331.20	303.90
35588963	35588964		0.00
35072889	35607300	5,129.35	246.21
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35098589	35637415	(2,528.37)	(121.36)
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041	168,932.63	8,108.77
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	4,436.06	212.93
35988062	36180715		0.00
35988062	36221401	15,555.21	746.65
35420948	36271040	3,279.19	157.40
36095379	36271041	28,032.60	1,345.56
36096196	36271042	129,501.43	6,216.07
36204335	36383347		0.00
36308739	36383348		0.00
36047938	36383821	4,939.69	237.11
36347629	36562360	102,286.96	4,909.77
36162805	36562367	4,938.22	237.03
36309136	36562369	636.41	30.57
TOTAL		**830,208.71**	**39,850.04**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950	1,939.76	93.11
29255064	29255064	261.88	12.57
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557	18.13	0.87
31672365	32061343	22.29	1.07
31630779	32686481		
29535933	33947106	(4,938.22)	(237.03)
33377496	34383018		
34646163	34646163	169.79	8.15
34536864	34769328		
TOTAL		**(2,526.37)**	**(121.26)**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9318446608
INVOICE DATE: 6/4/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
JUNE 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR MAY 2020 REFERENCE EXHIBIT I	$541,675.86

PAYMENT DUE BY 6/20/20 AMOUNT DUE $541,675.86

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 6/20/20

INVOICE STATEMENT NO: 9318446608
0
6/4/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

MAY 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(13,216)

ACTUAL COST:

WESTERN RECEIPTS	13,216
FUEL COSTS - WESTERN	$517,974.69
HANDLING COST - WESTERN	10,453.86
LIME CHARGES	1,646.00
UREA CHARGES	866.64
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	59,353
PRICE PER GALLON	$1.3568
% OF TOTAL BURN:	13.33%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

MAY 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(13,216)
ENDING BALANCE	266
CONTRACTUAL BALANCE	13,482
MAY RECEIPTS	13,216

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

MAY 2020 ACTUAL

ACTUAL FUEL COST

		WESTERN	
FUEL		$517,974.69	
HANDLING		$10,453.86	
LIME CHARGES		1,646.00	
UREA CHARGES		866.64	
ACT. CARB.		-	
TONS (WET)	13,216		
UNIT PRICE	$40		
TOTAL		$530,941.19	$530,941.19
AUX GEN FUEL COST (EXHIBIT IIA)			$10,734.67
TOTAL INVOICE TO MPPA			$541,675.86

Fuel	Fuel Hdlg	
$528,709.36	$12,966.50	$541,675.86
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

MAY 2020 ACTUAL

FUEL OIL USED IN GENERATION	59,353	GALS
PRICE PER GALLON	$1.3568	
TOTAL	$80,530.15	
MPPA % OF BURN	0.1333	
MPPA AUXILIARY FUEL COST	$10,734.67	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	$541,675.86		
1697760		$530,941.19	coal
1697700		$10,734.67	fuel oil
1697700			
TOTAL	$541,675.86	$541,675.86	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9318467629
INVOICE DATE: 6/8/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
JUNE 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF MAY 2020	$97,411.20

PAYMENT DUE BY 6/20/20

AMOUNT DUE $97,411.20

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 6/20/20

INVOICE STATEMENT NO: 9318467629

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
MAY 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$73,001.80	See Sched I
II	Gen Office Eng & Suprv - Allocation	$10,355.86	See Sched II
III	Employee Benefits	$1,786.10	**9260-0000-001-02**
IV	Payroll Taxes	$5,028.57	**4083-0000-001-02**
V	Admin & General Expenses	$7,238.87	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$97,411.20	

CONSUMERS ENERGY COMPANY
Campbell Unit 3

Summary of Production Expenses

MAY 2020 **ACTUAL**

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**		$214,557.08	($73,096.34)	$141,460.74
501	**5011-0000-001-02**	**10,968.99**	$249,672.06	($21,151.38)	$228,520.68
502	**5020-0000-001-02**	**16,200.05**	$320,351.71	$17,149.37	$337,501.08
505	**5050-0000-001-02**	**6,917.33**	$143,025.07	$1,086.02	$144,111.09
506	**5060-0000-001-02**	**2,585.70**	$32,645.36	$21,223.40	$53,868.76
510	**5100-0000-001-02**	**4,192.66**	$93,245.55	($5,898.47)	$87,347.08
511	**5110-0000-001-02**	**2,337.10**	$23,654.92	$25,034.59	$48,689.51
512	**5120-0000-001-02**	**16,986.48**	$194,480.93	$159,404.15	$353,885.08
513	**5130-0000-001-02**	**3,980.04**	$60,353.19	$22,564.41	$82,917.60
514	**5140-0000-001-02**	**2,043.32**	$13,165.88	$29,403.43	$42,569.31
Total		66,211.67	$1,345,151.75	$175,719.18	$1,520,870.93
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$64,567.28	$8,434.52	$73,001.80

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
MAY 2020 ACTUAL

Campbell 3 GO - E&S - Production			215,747.07	
MPPA OWNERSHIP %			4.80%	
MPPA - GO E&S SHARE			$10,355.86	
BILL MPPA			**$10,355.86**	
	5000-0000-001-02		**5,177.93**	
	5060-0000-001-02		**$5,177.93**	
			10,355.86	
GO E&S Labor =		$86,021.57	4.80%	$4,129.04

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,494.95	98	2	1,467.86	
BTS-Stm Exp	180250	148,554.22	29	71	43,606.99	
Fossil Train	180223	40,477.63	86	14	34,704.29	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	25,220.27	25	75	6,242.43	
		215,747.07			86,021.57	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
MAY 2020 Actual

Account		Amount	Less	Billing CR Addbacks	Balance	% of Total
920 **9200-0000-001-02**	**1,903.82**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921 **9210-0000-001-02**	**651.50**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922 **9220-0000-001-02**	-	(19,182,696.00)	19,182,696.00		$0	0.00%
923 **9230-0000-001-02**	**2,041.36**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924 **9240-0000-001-02**	**528.44**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925 **9250-0000-001-02**	**731.13**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926 **9260-0000-001-02**	**57.91**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928 **9280-0000-001-02**	**43.43**	572,500.00	0.00	1,647.00	$574,147	0.60%
930 **9300-0000-001-02**	**933.81**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931 **9310-0000-001-02**	**14.48**	166,781.00	0.00	2,219.00	$169,000	0.20%
935 **9350-0000-001-02**	**332.99**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
	7,238.87	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$150,810		
Indirect Pen & Ben =	$150,810	0.80%	$1,206
A & G Salaries =	$150,810	26.30%	$39,663

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9318733215**
INVOICE DATE: 7/23/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
JULY 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF JUNE 2020	$35,022.27	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF JUNE 2020	$79.26	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF JUNE 2020	0.00	

PAYMENT DUE BY 8/15/20 AMOUNT DUE $35,101.53

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 8/15/20

INVOICE STATEMENT NO: 9318733215

MICHIGAN PUBLIC POWER AGENCY

7/23/20

CONSUMERS ENERGY
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF JUNE 2020

Schedule II

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301		0.00
3014541	3014541	7,320.18	351.37
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	773.04	37.11
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	89,851.65	4,312.88
29090639	29303622		0.00
29255064	29255064	11,720.59	562.59
29342833	29649993	17,528.52	841.37
29648629	29952931	8,852.26	424.91
29342487	30136462		0.00
29344915	30136463	348.45	16.73
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	7,672.42	368.28
30461542	31464878		0.00
31593775	31903546	2,060.34	98.90
31594191	31903557	7.08	0.34
31672277	31903077	19,609.49	941.26
31732508	31903079		0.00
31768429	32014366	11,688.48	561.05
31768432	32014370	1,057.32	50.75
31672365	32061343	661.90	31.77
31594199	32182462	4,547.55	218.28
31769040	32182464	1,203.46	57.77
31769228	32547749	6,545.96	314.21
32080550	32547750		0.00
31630779	32686481	5,645.72	270.99
32762652	33432977		0.00
31338989	33434098	(37.08)	(1.78)
33365304	33900652		0.00
33470359	33947104	11,691.53	561.19
29535933	33947106		0.00
32762651	34070925		0.00
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	15,277.69	733.33
34066657	34484358	4,829.12	231.80
34275673	34640501	942.38	45.23
34498210	34640502	12,634.79	606.47
34646163	34646163	2,750.24	132.01
34275231	34769326	4,979.62	239.02
34536864	34769328	12,994.07	623.72
34616096	34770035	10,419.24	500.12
34066741	34929637		0.00
34688256	34929638		0.00
34763474	34929801	392.80	18.85
34763477	34947989	3,969.41	190.53
34763479	34947990	392.80	18.85
34550414	34949236		0.00

34686197	34949843		0.00
34815508	35084575	90,588.24	4,348.24
34686388	35084577		0.00
35117725	35247545	687.41	33.00
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	85,613.09	4,109.43
35588963	35588964		0.00
35072889	35607300		0.00
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041	(10,695.28)	(513.37)
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	24,165.47	1,159.94
35988062	36180715		0.00
35988062	36221401	4,182.24	200.75
35420948	36271040		0.00
36095379	36271041		0.00
36096196	36271042	5,077.35	243.71
36204335	36383347		0.00
36308739	36383348	71,862.02	3,449.38
36047938	36383821	13,156.20	631.50
36347629	36562360	1,523.79	73.14
36162805	36562367	28,173.97	1,352.35
36309136	36562369		0.00
36164627	36711154	1,397.52	67.08
36209181	36711157	9,567.58	459.24
36262102	36711320	20,822.48	999.48
36347623	36711321	5,733.68	275.22
36370395	36711323	7,256.52	348.31
36557894	36711324	10,666.22	511.98
36564435	36711325	41,699.06	2,001.55
36464982	36722386	39,820.99	1,911.46
TOTAL		**729,629.57**	**35,022.27**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950		
29255064	29255064	928.75	44.58
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557		
31672365	32061343	35.00	1.68
31630779	32686481		
29535933	33947106		
33377496	34383018		
34646163	34646163	687.50	33.00
34536864	34769328		
TOTAL		**1,651.25**	**79.26**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9318675069
INVOICE DATE: 7/6/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
JULY 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR JUNE 2020 REFERENCE EXHIBIT I	$394,439.32
	MAY FUEL OIL ADJUSTMENT	(4,743.23)

PAYMENT DUE BY 7/20/20 AMOUNT DUE $389,696.09

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 7/20/20

INVOICE STATEMENT NO: 9318675069
0
7/6/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

JUNE 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	19,320
ADJUSTMENTS	0
WESTERN BURN:	(15,380)

ACTUAL COST:

WESTERN RECEIPTS	9,542
FUEL COSTS - WESTERN	$366,012.04
HANDLING COST - WESTERN	14,380.30
LIME CHARGES	5,553.23
UREA CHARGES	4,626.13
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	46,430
PRICE PER GALLON	$1.3328
% OF TOTAL BURN:	6.25%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

JUNE 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	19,320
ADJUSTMENTS	0
BURN	(15,380)
ENDING BALANCE	3,940
CONTRACTUAL BALANCE	13,482
JUNE RECEIPTS	9,542

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

JUNE 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$366,012.04	
HANDLING			$14,380.30	
LIME CHARGES			5,553.23	
UREA CHARGES			4,626.13	
ACT. CARB.			-	
TONS (WET)		9,542		
UNIT PRICE		$41		
	TOTAL		$390,571.70	$390,571.70
	AUX GEN FUEL COST (EXHIBIT IIA)			$3,867.62
	TOTAL INVOICE TO MPPA			$394,439.32

Fuel	Fuel Hdlg	
$369,879.66	$24,559.66	$394,439.32
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

JUNE 2020 ACTUAL

FUEL OIL USED IN GENERATION	46,430	GALS
PRICE PER GALLON	$1.3328	
TOTAL	$61,881.90	
MPPA % OF BURN	0.0625	
MPPA AUXILIARY FUEL COST	$3,867.62	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

MAY 2020 ADJUSTED

FUEL OIL USED IN GENERATION		59,353	GALS
PRICE PER GALLON		$1.3568	
	TOTAL	$80,530.15	
MPPA % OF BURN		0.0744	
MPPA AUXILIARY FUEL COST -	ACTUAL	$5,991.44	
	BILLED	10,734.67	
	ADJUSTMENT	($4,743.23)	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	$389,696.09		
1697760		$390,571.70	coal
1697700		$3,867.62	fuel oil
1697700	4,743.23		fuel oil-ad
TOTAL	$394,439.32	$394,439.32	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9318676725
INVOICE DATE: 7/9/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
JULY 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF JUNE 2020	$97,956.73

PAYMENT DUE BY 6/20/20

AMOUNT DUE $97,956.73

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 6/20/20

INVOICE STATEMENT NO: 9318676725

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
JUNE 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$68,588.76	See Sched I
II	Gen Office Eng & Suprv - Allocation	$13,646.29	See Sched II
III	Employee Benefits	$1,970.40	**9260-0000-001-02**
IV	Payroll Taxes	$5,547.43	**4083-0000-001-02**
V	Admin & General Expenses	$8,203.86	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$97,956.73	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
JUNE 2020 ACTUAL

FERC Account			Labor	Other	Total
500	5000-0000-001-02	12,885.26	$252,452.29	$15,990.71	$268,443.00
501	5011-0000-001-02	196.44	$264,561.27	($260,468.68)	$4,092.59
502	5020-0000-001-02	17,610.77	$356,269.06	$10,622.04	$366,891.10
505	5050-0000-001-02	7,864.66	$162,831.14	$1,015.97	$163,847.11
506	5060-0000-001-02	2,653.83	$34,212.60	$21,075.57	$55,288.17
510	5100-0000-001-02	5,170.84	$100,673.59	$7,052.26	$107,725.85
511	5110-0000-001-02	2,670.01	$21,541.00	$34,084.24	$55,625.24
512	5120-0000-001-02	14,820.78	$180,517.68	$128,248.65	$308,766.33
513	5130-0000-001-02	3,373.06	$39,206.60	$31,065.38	$70,271.98
514	5140-0000-001-02	1,343.09	$18,605.94	$9,375.11	$27,981.05
Total		68,588.74	$1,430,871.17	($1,938.75)	$1,428,932.42
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$68,681.82	($93.06)	$68,588.76

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
JUNE 2020 ACTUAL

Campbell 3 GO - E&S - Production		284,297.65	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$13,646.29	
BILL MPPA		**$13,646.29**	
5000-0000-001-02		**6,823.14**	
5060-0000-001-02		**$6,823.15**	
		13,646.29	
GO E&S Labor =	$147,973.06	4.80%	$7,102.71

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	9,714.31			9,714.31	
Sys Prot	122258	1,505.15	99	1	1,503.14	
BTS-Stm Exp	180250	147,167.39	27	73	39,175.67	
Fossil Train	180223	34,414.59	95	5	32,534.30	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	58,694.00			58,694.00	
Security	141065	32,802.21	19	81	6,351.64	
		284,297.65			147,973.06	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
JUNE 2020 Actual

Account		Amount	Less	Billing CR Addbacks	Balance	% of Total
920 **9200-0000-001-02**	**2,157.62**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921 **9210-0000-001-02**	**738.35**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922 **9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923 **9230-0000-001-02**	**2,313.49**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924 **9240-0000-001-02**	**598.88**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925 **9250-0000-001-02**	**828.59**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926 **9260-0000-001-02**	**65.63**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928 **9280-0000-001-02**	**49.22**	572,500.00	0.00	1,647.00	$574,147	0.60%
930 **9300-0000-001-02**	**1,058.30**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931 **9310-0000-001-02**	**16.41**	166,781.00	0.00	2,219.00	$169,000	0.20%
935 **9350-0000-001-02**	**377.38**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
	8,203.87	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$170,914		
Indirect Pen & Ben =	$170,914	0.80%	$1,367
A & G Salaries =	$170,914	26.30%	$44,950

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9319018231**
INVOICE DATE: 8/25/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
AUG 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF JULY 2020	$32,898.31	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF JULY 2020	$2,741.93	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF JULY 2020	0.00	

PAYMENT DUE BY 9/15/20

AMOUNT DUE $35,640.24

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 9/15/20

INVOICE STATEMENT NO: 9319018231

MICHIGAN PUBLIC POWER AGENCY

8/25/20

CONSUMERS ENERGY
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF JULY 2020

Schedule II

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919	7,506.50	360.31
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301		0.00
3014541	3014541		0.00
3014582	3014582	1,430.26	68.65
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	985.50	47.30
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	1,071.82	51.45
29090639	29303622		0.00
29255064	29255064	79,129.00	3,798.19
29342833	29649993	63,888.48	3,066.65
29648629	29952931	6,480.18	311.05
29342487	30136462		0.00
29344915	30136463	178.22	8.55
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	3,196.62	153.44
30461542	31464878		0.00
31593775	31903546	2,190.76	105.16
31594191	31903557	197.96	9.50
31672277	31903077	(20,353.29)	(976.96)
31732508	31903079		0.00
31768429	32014366	7,561.19	362.94
31768432	32014370	5,737.66	275.41
31672365	32061343	84.73	4.07
31594199	32182462	1,811.97	86.97
31769040	32182464	2,616.54	125.59
31769228	32547749	2,662.50	127.80
32080550	32547750		0.00
31630779	32686481	6,363.41	305.44
32762652	33432977		0.00
31338989	33434098		0.00
33365304	33900652		0.00
33470359	33947104	6,899.04	331.15
29535933	33947106		0.00
32762651	34070925	206.66	9.92
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	39,334.25	1,888.04
34066657	34484358		0.00
34275673	34640501	934.77	44.87
34498210	34640502	4,757.15	228.34
34646163	34646163	392.09	18.82
34275231	34769326	10,298.51	494.33
34536864	34769328	56,921.06	2,732.21
34616096	34770035	137,299.73	6,590.39
34066741	34929637		0.00
34688256	34929638		0.00
34763474	34929801		0.00
34763477	34947989	5,070.39	243.38
34763479	34947990		0.00

34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	51,186.94	2,456.97
34686388	35084577		0.00
35117725	35247545	1,842.33	88.43
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	6,432.14	308.74
35588963	35588964		0.00
35072889	35607300		0.00
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35624240	35624240	5,612.91	269.42
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041	(11,725.60)	(562.83)
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	10,097.48	484.68
35988062	36180715		0.00
35988062	36221401	691.31	33.18
35420948	36271040		0.00
36095379	36271041	688.88	33.07
36096196	36271042	73,129.76	3,510.23
36204335	36383347		0.00
36308739	36383348	3,556.55	170.71
36047938	36383821	(26,501.60)	(1,272.08)
36347629	36562360		0.00
36162805	36562367	18,212.28	874.19
36309136	36562369	18,596.57	892.64
36164627	36711154	2,048.38	98.32
36209181	36711157	24,512.99	1,176.62
36262102	36711320		0.00
36347623	36711321		0.00
36370395	36711323		0.00
36557894	36711324		0.00
36564435	36711325		0.00
36464982	36722386		0.00
36147109	36887938	25,980.71	1,247.07
36675972	36890775	34,591.62	1,660.40
36693696	36890776	2,394.43	114.93
36744474	36890777	207.37	9.95
36467356	36904335	8,972.01	430.68
TOTAL		**685,381.12**	**32,898.31**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950		
29255064	29255064	8,362.50	401.40
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557	6.25	0.30
31672365	32061343	4.38	0.21
31630779	32686481		
29535933	33947106		
33377496	34383018		

34646163	34646163	98.13	4.71
34536864	34769328		
34793531	35869041	14,611.88	701.37
36047938	36383821	34,040.42	1,633.94
TOTAL		**57,123.56**	**2,741.93**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9318892629
INVOICE DATE: 8/6/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
AUGUST 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR JULY 2020 REFERENCE EXHIBIT I	$418,521.98
	JUNE FUEL OIL ADJUSTMENT	2,091.00

PAYMENT DUE BY 8/20/20 AMOUNT DUE $420,612.98

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 8/20/20

INVOICE STATEMENT NO: 9318892629
0
8/6/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

JULY 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	14,470
ADJUSTMENTS	0
WESTERN BURN:	(11,486)

ACTUAL COST:

WESTERN RECEIPTS	10,498
FUEL COSTS - WESTERN	$398,561.47
HANDLING COST - WESTERN	10,833.50
LIME CHARGES	2,653.08
UREA CHARGES	2,173.40
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	56,886
PRICE PER GALLON	$1.3263
% OF TOTAL BURN:	5.70%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

JULY 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	14,470
ADJUSTMENTS	0
BURN	(11,486)
ENDING BALANCE	2,984
CONTRACTUAL BALANCE	13,482
JULY RECEIPTS	10,498

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

JULY 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$398,561.47	
HANDLING			$10,833.50	
LIME CHARGES			2,653.08	
UREA CHARGES			2,173.40	
ACT. CARB.			-	
TONS (WET)		10,498		
UNIT PRICE		$39		
	TOTAL		$414,221.45	$414,221.45
	AUX GEN FUEL COST (EXHIBIT IIA)			$4,300.53
	TOTAL INVOICE TO MPPA			$418,521.98

Fuel	Fuel Hdlg	
$402,862.00	$15,659.98	$418,521.98
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

JULY 2020 ACTUAL

FUEL OIL USED IN GENERATION	56,886	GALS
PRICE PER GALLON	$1.3263	
TOTAL	$75,447.90	
MPPA % OF BURN	0.057	
MPPA AUXILIARY FUEL COST	$4,300.53	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY
AUXILIARY FUEL COST
JUNE 2020 ADJUSTED

FUEL OIL USED IN GENERATION		71,532	GALS
PRICE PER GALLON		$1.3328	
	TOTAL	$95,337.85	
MPPA % OF BURN		0.0625	
MPPA AUXILIARY FUEL COST -	ACTU	$5,958.62	
	BILLED	3,867.62	
	ADJUSTMENT	$2,091.00	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	**$420,612.98**		
1697760		**$414,221.45**	coal
1697700		**$4,300.53**	fuel oil
1697700		**$2,091.00**	fuel oil-ad
TOTAL	$420,612.98	$420,612.98	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9318829642
INVOICE DATE: 8/10/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
AUGUST 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF JULY 2020	$124,389.56

PAYMENT DUE BY 8/20/20

AMOUNT DUE $124,389.56

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 8/20/20

INVOICE STATEMENT NO: 9318829642

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
JULY 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$97,983.92	See Sched I
II	Gen Office Eng & Suprv - Allocation	$8,899.83	See Sched II
III	Employee Benefits	$2,059.73	**9260-0000-001-02**
IV	Payroll Taxes	$5,798.93	**4083-0000-001-02**
V	Admin & General Expenses	$9,647.15	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$124,389.56	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3

Summary of Production Expenses

JULY 2020 **ACTUAL**

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**9,947.57**	$188,727.69	$18,513.45	$207,241.14
501	**5011-0000-001-02**	**10,412.28**	$319,891.83	($102,969.43)	$216,922.40
502	**5020-0000-001-02**	**21,268.83**	$423,319.59	$19,781.01	$443,100.60
505	**5050-0000-001-02**	**9,075.37**	$188,333.78	$736.48	$189,070.26
506	**5060-0000-001-02**	**2,476.15**	$33,618.82	$17,967.58	$51,586.40
510	**5100-0000-001-02**	**4,626.20**	$89,463.89	$6,915.19	$96,379.08
511	**5110-0000-001-02**	**2,787.13**	$20,627.97	$37,437.16	$58,065.13
512	**5120-0000-001-02**	**34,486.45**	$231,636.37	$486,831.31	$718,467.68
513	**5130-0000-001-02**	**1,388.69**	$35,582.05	($6,650.91)	$28,931.14
514	**5140-0000-001-02**	**1,515.26**	$26,186.33	$5,381.58	$31,567.91
Total		97,983.93	$1,557,388.32	$483,943.42	$2,041,331.74
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$74,754.64	$23,229.28	$97,983.92

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
JULY 2020 ACTUAL

Campbell 3 GO - E&S - Production		185,413.19	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$8,899.83	
BILL MPPA		**$8,899.83**	
5000-0000-001-02		**4,449.92**	
5060-0000-001-02		**$4,449.91**	
		8,899.83	
GO E&S Labor =	$93,035.40	4.80%	$4,465.70

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,644.29	94	6	1,530.92	
BTS-Stm Exp	180250	176,845.06	28	72	48,737.88	
Fossil Train	180223	44,882.98	72	28	32,280.93	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	(37,959.14)	28	72	10,485.67	
		185,413.19			93,035.40	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
JULY 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,537.20**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**868.24**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**2,720.50**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**704.24**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**974.36**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**77.18**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**57.88**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**1,244.48**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**19.29**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**443.77**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		9,647.14	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$200,982		
Indirect Pen & Ben =	$200,982	0.80%	$1,608
A & G Salaries =	$200,982	26.30%	$52,858

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: **9319170652**
INVOICE DATE: 9/16/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
SEPT 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF AUG 2020	$53,304.85	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF AUG 2020	$867.65	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF AUG 2020	0.00	

PAYMENT DUE BY 10/15/20 AMOUNT DUE $54,172.50

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 10/15/20

INVOICE STATEMENT NO: 9319170652

MICHIGAN PUBLIC POWER AGENCY

9/16/20

CONSUMERS ENERGY
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF AUGUST 2020

Schedule II

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301		0.00
3014541	3014541		0.00
3014582	3014582		0.00
3014700	3014700	6,675.00	320.40
3014808	3014808	14,418.53	692.09
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	1,006.05	48.29
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	(7,894.42)	(378.93)
29090639	29303622		0.00
29255064	29255064	48,444.76	2,325.35
29342833	29649993	174,654.74	8,383.43
29648629	29952931	35,616.27	1,709.58
29342487	30136462		0.00
29344915	30136463		0.00
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	9,142.78	438.85
30461542	31464878		0.00
31593775	31903546	(123.50)	(5.93)
31594191	31903557		0.00
31672277	31903077	207.37	9.95
31732508	31903079		0.00
31768429	32014366	940.93	45.16
31768432	32014370	3,076.34	147.66
31672365	32061343		0.00
31594199	32182462	3,349.56	160.78
31769040	32182464	1,519.56	72.94
31769228	32547749	1,461.72	70.16
32080550	32547750		0.00
31630779	32686481	2,216.35	106.38
32762652	33432977		0.00
31338989	33434098		0.00
33365304	33900652		0.00
33470359	33947104	51,861.88	2,489.37
29535933	33947106		0.00
32762651	34070925	169.45	8.13
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	75,560.23	3,626.89
34066657	34484358		0.00
34275673	34640501	74.52	3.58
34498210	34640502	24,124.35	1,157.97
34646163	34646163	349.34	16.77
34275231	34769326	57,929.06	2,780.59
34536864	34769328	51,119.04	2,453.71
34616096	34770035	15,055.07	722.64
34066741	34929637		0.00
34688256	34929638		0.00
34763474	34929801		0.00

34763477	34947989		0.00
34763479	34947990		0.00
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	168,864.03	8,105.47
34686388	35084577		0.00
35117725	35247545	579.26	27.80
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	3,272.77	157.09
35588963	35588964		0.00
35072889	35607300	1,000.71	48.03
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35624240	35624240		0.00
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041	4,447.08	213.46
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	36,486.61	1,751.36
35988062	36180715		0.00
35988062	36221401	3,691.13	177.17
35420948	36271040	6,062.91	291.02
36095379	36271041	80.38	3.86
36096196	36271042	1,433.30	68.80
36204335	36383347		0.00
36308739	36383348		0.00
36047938	36383821		0.00
36347629	36562360		0.00
36162805	36562367	16,558.83	794.82
36309136	36562369	3,566.85	171.21
36164627	36711154	2,509.43	120.45
36209181	36711157	89,047.01	4,274.26
36262102	36711320		0.00
36347623	36711321		0.00
36370395	36711323	5,776.97	277.29
36557894	36711324		0.00
36564435	36711325	29,466.27	1,414.38
36464982	36722386	17,273.08	829.11
36147109	36887938	40,107.20	1,925.15
36675972	36890775	472.75	22.69
36693696	36890776	5,960.41	286.10
36744474	36890777	6,449.76	309.59
36467356	36904335	4,132.40	198.36
36524623	36987123	4,896.76	235.04
36525328	36987124	5,543.34	266.08
36676472	36987126	120.85	5.80
36746601	36987129	102.16	4.98
36468351	36997251	75,455.73	3,621.89
36798266	36997253	6,202.97	297.74
TOTAL		**1,110,515.93**	**53,304.85**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950		
29255064	29255064	4,503.55	216.17

29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557		
31672365	32061343		
31630779	32686481		
29535933	33947106	51.30	2.46
33377496	34383018		
34646163	34646163	87.30	4.19
34536864	34769328		
34793531	35869041	(2,259.80)	(108.47)
36096196	36271042	159.17	7.64
36047938	36383821	15,534.53	745.66
TOTAL		**18,076.05**	**867.65**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319082329
INVOICE DATE: 9/3/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
SEPT 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR AUGUST 2020 REFERENCE EXHIBIT I	$610,974.68

PAYMENT DUE BY 9/20/20 AMOUNT DUE $610,974.68

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 9/20/20

INVOICE STATEMENT NO: 9319082329
0
9/3/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

AUGUST 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(16,035)

ACTUAL COST:

WESTERN RECEIPTS	16,035
FUEL COSTS - WESTERN	$581,862.05
HANDLING COST - WESTERN	14,880.48
LIME CHARGES	6,280.92
UREA CHARGES	5,587.97
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	33,044
PRICE PER GALLON	$1.3343
% OF TOTAL BURN:	5.36%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

AUGUST 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(16,035)
ENDING BALANCE	(2,553)
CONTRACTUAL BALANCE	13,482
AUGUST RECEIPTS	16,035

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

AUGUST 2020 ACTUAL

ACTUAL FUEL COST

		WESTERN	
FUEL		$581,862.05	
HANDLING		$14,880.48	
LIME CHARGES		6,280.92	
UREA CHARGES		5,587.97	
ACT. CARB.		-	
TONS (WET)	16,035		
UNIT PRICE	$38		
TOTAL		$608,611.42	$608,611.42
AUX GEN FUEL COST (EXHIBIT IIA)			$2,363.26
TOTAL INVOICE TO MPPA			$610,974.68

Fuel	Fuel Hdlg	
$584,225.31	$26,749.37	$610,974.68
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

AUGUST 2020 ACTUAL

FUEL OIL USED IN GENERATION	33,044	GALS
PRICE PER GALLON	$1.3343	
TOTAL	$44,090.61	
MPPA % OF BURN	0.0536	
MPPA AUXILIARY FUEL COST	$2,363.26	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	$610,974.68		
1697760		$608,611.42	coal
1697700		$2,363.26	fuel oil
1697700			
TOTAL	$610,974.68	$610,974.68	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319090455
INVOICE DATE: 9/8/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
SEPT 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF AUG 2020	$102,296.41

PAYMENT DUE BY 9/20/20

AMOUNT DUE $102,296.41

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 9/20/20

INVOICE STATEMENT NO: 9319090455

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
AUG 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$73,944.89	See Sched I
II	Gen Office Eng & Suprv - Allocation	$4,091.06	See Sched II
III	Employee Benefits	$2,187.75	**9260-0000-001-02**
IV	Payroll Taxes	$6,159.37	**4083-0000-001-02**
V	Admin & General Expenses	$7,347.93	See Sched V-A
VI	Insurance	$8,565.41	**9240-0000-001-2**
	Total	$102,296.41	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
AUG 2020 ACTUAL

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**10,272.17**	$184,663.59	$29,339.99	$214,003.58
501	**5011-0000-001-02**	**4,556.60**	$313,256.28	($218,327.08)	$94,929.20
502	**5020-0000-001-02**	**19,316.20**	$368,750.61	$33,670.30	$402,420.91
505	**5050-0000-001-02**	**7,918.40**	$163,555.82	$1,410.76	$164,966.58
506	**5060-0000-001-02**	**4,039.56**	$39,785.39	$44,372.05	$84,157.44
510	**5100-0000-001-02**	**5,116.60**	$98,610.93	$7,984.91	$106,595.84
511	**5110-0000-001-02**	**4,553.32**	$40,963.93	$53,896.97	$94,860.90
512	**5120-0000-001-02**	**14,712.66**	$163,685.74	$142,828.10	$306,513.84
513	**5130-0000-001-02**	**1,999.62**	$32,470.31	$9,188.43	$41,658.74
514	**5140-0000-001-02**	**1,459.75**	$23,756.49	$6,655.03	$30,411.52
Total		73,944.88	$1,429,499.09	$111,019.46	$1,540,518.55
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$68,615.96	$5,328.93	$73,944.89

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
AUG 2020 ACTUAL

Campbell 3 GO - E&S - Production		85,230.44	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$4,091.06	
BILL MPPA		**$4,091.06**	
	5000-0000-001-02	**2,045.53**	
	5060-0000-001-02	**$2,045.53**	
		4,091.06	
GO E&S Labor =	$323,508.80	4.80%	$15,528.42

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,479.57	99	1	1,475.39	
BTS-Stm Exp	180250	45,820.21	0	0	186,229.81	
Fossil Train	180223	32,004.64	0	0	32,690.24	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	5,926.02	0	0	103,113.36	
		85,230.44			323,508.80	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
AUG 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**1,932.51**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**661.31**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	-	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**2,072.12**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**536.40**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**742.14**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**58.78**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**44.09**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**947.88**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**14.70**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**338.01**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		7,347.94	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$153,082		
Indirect Pen & Ben =	$153,082	0.80%	$1,225
A & G Salaries =	$153,082	26.30%	$40,261

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: 9319403269
INVOICE DATE: 10/20/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
OCT 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF SEPT 2020	$53,239.05	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF SEPT 2020	$591.57	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF SEPT 2020	0.00	

PAYMENT DUE BY 11/15/20 AMOUNT DUE $53,830.62

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 11/15/20

INVOICE STATEMENT NO: 9319403269

MICHIGAN PUBLIC POWER AGENCY

10/20/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF SEPTEMBER 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919	1,235.25	59.29
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301	172.19	8.27
3014541	3014541		0.00
3014582	3014582		0.00
3014700	3014700		0.00
3014808	3014808		0.00
3014858	3014858	3,023.76	145.14
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	1,455.78	69.88
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	618.89	29.71
28919497	29084950	13.16	0.63
29090639	29303622		0.00
29255064	29255064	11,759.72	564.47
29342833	29649993	48,315.36	2,319.14
29648629	29952931	(32,903.48)	(1,579.37)
29342487	30136462		0.00
29344915	30136463		0.00
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	11,115.97	533.57
30461542	31464878		0.00
31593775	31903546	12,820.15	615.37
31594191	31903557		0.00
31672277	31903077		0.00
31732508	31903079		0.00
31768429	32014366	(12,668.99)	(608.11)
31768432	32014370	104.82	5.03
31672365	32061343		0.00
31594199	32182462	7,023.76	337.14
31769040	32182464	1,883.71	90.42
31769228	32547749	5,871.35	281.82
32080550	32547750		0.00
31630779	32686481	1,276.82	61.29
32762652	33432977		0.00
31338989	33434098		0.00
33365304	33900652		0.00
33470359	33947104	55,808.42	2,678.80
29535933	33947106		0.00
32762651	34070925	327.11	15.70
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	115,216.88	5,530.41
34066657	34484358		0.00
34275673	34640501	15,232.05	731.14
34498210	34640502	11,563.41	555.04
34646163	34646163	521.80	25.05
34275231	34769326	116,850.69	5,608.83
34536864	34769328	27,837.55	1,336.20
34616096	34770035	1,457.25	69.95
34066741	34929637		0.00

34688256	34929638		0.00
34763474	34929801		0.00
34763477	34947989		0.00
34763479	34947990		0.00
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	64,316.91	3,087.21
34686388	35084577		0.00
35117725	35247545	2,260.85	108.52
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	3,890.58	186.75
35588963	35588964		0.00
35072889	35607300	85.37	4.10
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35624240	35624240		0.00
35098589	35637415		0.00
33916264	35702594	115,440.44	5,541.14
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041		0.00
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
35934141	36098425	11,995.93	575.80
35988062	36180715		0.00
35988062	36221401	2,628.44	126.17
35420948	36271040	29,331.40	1,407.91
36095379	36271041	4,887.33	234.59
36096196	36271042	2,512.49	120.60
36204335	36383347		0.00
36308739	36383348		0.00
36047938	36383821		0.00
36347629	36562360		0.00
36162805	36562367	3,685.99	176.93
36309136	36562369	27,351.62	1,312.88
36164627	36711154	1,887.64	90.61
36209181	36711157	24,249.59	1,163.98
36262102	36711320		0.00
36347623	36711321		0.00
36370395	36711323		0.00
36557894	36711324		0.00
36564435	36711325		0.00
36464982	36722386		0.00
36147109	36887938	142,842.06	6,856.42
36675972	36890775	73,106.45	3,509.11
36693696	36890776	15,836.25	760.14
36744474	36890777	15,207.05	729.94
36467356	36904335	627.39	30.11
36524623	36987123		0.00
36525328	36987124	43,659.58	2,095.66
36676472	36987126	76,648.50	3,679.13
36746601	36987129		0.00
36468351	36997251	14,176.78	680.49
36798266	36997253	5,925.78	284.44
36700977	37120123	20,659.60	991.63
TOTAL		**1,109,147.40**	**53,239.05**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share

21840037	21840037		
28919497	29084950		
29255064	29255064	1,471.25	70.62
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557		
31672365	32061343		
31630779	32686481		
29535933	33947106		
33377496	34383018		
34646163	34646163	130.42	6.26
34536864	34769328		
34793531	35869041		
36096196	36271042	278.13	13.39
36047938	36383821	10,443.77	501.30
TOTAL		**12,323.57**	**591.57**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319313761
INVOICE DATE: 10/6/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
OCT 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR SEPT 2020 REFERENCE EXHIBIT I	$561,525.83

PAYMENT DUE BY 10/20/20 AMOUNT DUE $561,525.83

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 10/20/20

INVOICE STATEMENT NO: 9319313761
0
10/6/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

SEPTEMBER 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(15,299)

ACTUAL COST:

WESTERN RECEIPTS	15,299
FUEL COSTS - WESTERN	$542,135.36
HANDLING COST - WESTERN	8,261.46
LIME CHARGES	2,667.68
UREA CHARGES	5,653.46
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	40,625
PRICE PER GALLON	$1.3343
% OF TOTAL BURN:	5.18%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

SEPTEMBER 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(15,299)
ENDING BALANCE	(1,817)
CONTRACTUAL BALANCE	13,482
SEPTEMBER RECEIPTS	15,299

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

SEPTEMBER 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$542,135.36	
HANDLING			$8,261.46	
LIME CHARGES			2,667.68	
UREA CHARGES			5,653.46	
ACT. CARB.			-	
TONS (WET)		15,299		
UNIT PRICE		$37		
	TOTAL		$558,717.96	$558,717.96
	AUX GEN FUEL COST (EXHIBIT IIA)			$2,807.87
	TOTAL INVOICE TO MPPA			$561,525.83

Fuel	Fuel Hdlg	
$544,943.23	$16,582.60	$561,525.83
1510-0000-000-02	5011-0000-000-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

SEPTEMBER 2020 ACTUAL

FUEL OIL USED IN GENERATION	40,625	GALS
PRICE PER GALLON	$1.3343	
TOTAL	$54,205.94	
MPPA % OF BURN	0.0518	
MPPA AUXILIARY FUEL COST	$2,807.87	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	**$561,525.83**		
1697760		**$558,717.96**	coal
1697700		**$2,807.87**	fuel oil
1697700			
TOTAL	$561,525.83	$561,525.83	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319318872
INVOICE DATE: 10/7/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
OCT 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF SEPT 2020	$114,850.20

PAYMENT DUE BY 10/20/20

AMOUNT DUE $114,850.20

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 10/20/20

INVOICE STATEMENT NO: 9319318872

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
SEPT 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$83,064.13	See Sched I
II	Gen Office Eng & Suprv - Allocation	$15,069.71	See Sched II
III	Employee Benefits	$2,074.76	**9260-0000-001-02**
IV	Payroll Taxes	$5,841.23	**4083-0000-001-02**
V	Admin & General Expenses	$8,800.37	See Sched V-A
VI	Insurance	$0.00	**9240-0000-001-2**
	Total	$114,850.20	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
SEPT 2020 ACTUAL

FERC Account			Labor	Other	Total
500	5000-0000-001-02	10,248.89	$196,927.46	$16,591.01	$213,518.47
501	5011-0000-001-02	10,130.15	$295,834.14	($84,789.32)	$211,044.82
502	5020-0000-001-02	19,844.91	$387,024.87	$26,410.66	$413,435.53
505	5050-0000-001-02	8,726.13	$180,757.04	$1,037.36	$181,794.40
506	5060-0000-001-02	2,873.96	$34,910.98	$24,963.18	$59,874.16
510	5100-0000-001-02	5,246.41	$101,915.10	$7,385.08	$109,300.18
511	5110-0000-001-02	4,237.39	$39,286.78	$48,992.27	$88,279.05
512	5120-0000-001-02	17,719.63	$208,826.93	$160,332.12	$369,159.05
513	5130-0000-001-02	2,006.32	$28,068.31	$13,730.06	$41,798.37
514	5140-0000-001-02	2,030.34	$24,973.83	$17,324.87	$42,298.70
Total		83,064.13	$1,498,525.44	$231,977.29	$1,730,502.73
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$71,929.22	$11,134.91	$83,064.13

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
SEPT 2020 ACTUAL

Campbell 3 GO - E&S - Production		313,952.38	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$15,069.71	
BILL MPPA		**$15,069.71**	
	5000-0000-001-02	**7,534.86**	
	5060-0000-001-02	**$7,534.85**	
		15,069.71	
GO E&S Labor =	$163,938.66	4.80%	$7,869.06

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	9,714.31			9,714.31	
Sys Prot	122258	1,510.75	99	1	1,508.78	
BTS-Stm Exp	180250	180,037.67	33	67	59,207.58	
Fossil Train	180223	36,319.04	90	10	32,447.96	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	53,366.60			53,366.60	
Security	141065	33,004.01	24	76	7,693.43	
		313,952.38			163,938.66	

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
SEPT 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,314.50**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**792.03**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**2,481.70**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**642.43**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**888.84**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**70.40**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**52.80**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**1,135.25**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**17.60**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**404.82**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		8,800.37	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$183,341		
Indirect Pen & Ben =	$183,341	0.80%	$1,467
A & G Salaries =	$183,341	26.30%	$48,219

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: 9319513290
INVOICE DATE: 11/19/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
NOV 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF OCT 2020	$60,437.81	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF OCT 2020	$1,762.54	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF OCT 2020	0.00	

PAYMENT DUE BY 12/15/20 AMOUNT DUE $62,200.35

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 12/15/20

INVOICE STATEMENT NO: 9319513290

MICHIGAN PUBLIC POWER AGENCY

11/19/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF OCTOBER 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998	120,925.50	5,804.42
3014301	3014301		0.00
3014541	3014541		0.00
3014582	3014582		0.00
3014700	3014700		0.00
3014808	3014808		0.00
3014858	3014858		0.00
3015026	3015026	7,777.71	373.33
3015030	3015030	1,592.16	76.42
3015039	3015039	3,186.31	152.94
12207242	12518451	(197,284.93)	(8,909.80)
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	1,164.69	55.91
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093	122.40	5.88
28919497	29084950		0.00
29090639	29303622		0.00
29255064	29255064	15,632.07	750.34
29342833	29649993	15,300.96	734.45
29648629	29952931	653.52	31.37
29342487	30136462		0.00
29344915	30136463		0.00
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867	1,663.74	79.86
30461542	31464878		0.00
31593775	31903546	11,191.12	537.17
31594191	31903557		0.00
31672277	31903077		0.00
31732508	31903079		0.00
31768429	32014366	3,035.81	145.72
31768432	32014370	326.88	15.69
31672365	32061343		0.00
31594199	32182462	3,701.98	177.70
31769040	32182464	106.12	5.09
31769228	32547749	1,608.46	77.21
32080550	32547750		0.00
31630779	32686481	182.41	8.76
32762652	33432977		0.00
31338989	33434098		0.00
33365304	33900652		0.00
33470359	33947104	7,037.45	337.80
29535933	33947106		0.00
32762651	34070925		0.00
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	26,467.90	1,270.46
34066657	34484358		0.00
34275673	34640501	(6,405.02)	(307.44)
34498210	34640502	14,753.61	708.17
34646163	34646163	99,833.32	4,792.00

34275231	34769326	14,162.27	679.79
34536864	34769328	25,588.84	1,228.26
34616096	34770035	2,714.66	130.30
34066741	34929637		0.00
34688256	34929638		0.00
34763474	34929801	1,788.02	85.82
34763477	34947989		0.00
34763479	34947990	1,788.02	85.82
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	151,405.61	7,267.47
34686388	35084577		0.00
35117725	35247545	524.06	25.15
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	3,118.78	149.70
35588963	35588964		0.00
35072889	35607300		0.00
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35624240	35624240		0.00
35098589	35637415		0.00
33916264	35702594	38,562.88	1,851.02
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041		0.00
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
36097009	36097009	37,851.70	1,816.88
35934141	36098425	3,024.68	145.18
35988062	36180715		0.00
35988062	36221401	1,843.50	88.49
35420948	36271040	162,297.75	7,790.29
36095379	36271041	23,118.15	1,109.67
36096196	36271042	35,538.75	1,705.86
36204335	36383347		0.00
36308739	36383348		0.00
36047938	36383821		0.00
36347629	36562360		0.00
36162805	36562367	34,380.05	1,650.24
36309136	36562369	(3,610.03)	(173.28)
36164627	36711154	1,988.61	95.45
36209181	36711157		0.00
36262102	36711320		0.00
36347623	36711321		0.00
36370395	36711323		0.00
36557894	36711324		0.00
36564435	36711325		0.00
36464982	36722386		0.00
36147109	36887938	(0.45)	(0.02)
36675972	36890775		0.00
36693696	36890776	21,406.93	1,027.53
36744474	36890777	29,705.45	1,425.86
36467356	36904335		0.00
36524623	36987123		0.00
36525328	36987124		0.00
36676472	36987126	55,540.74	2,665.96
36746601	36987129		0.00
36468351	36997251	817.12	39.22
36798266	36997253	6,832.16	327.94
36700977	37120123	448,049.08	21,506.32
36150435	37852662	16,446.28	789.42
TOTAL		**1,247,457.78**	**60,437.81**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950		
29255064	29255064	1,719.17	82.52
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557		
31672365	32061343		
31630779	32686481		
29535933	33947106		
33377496	34383018		
34646163	34646163	24,907.50	1,195.56
34536864	34769328		
34793531	35869041		
36096196	36271042	138.75	6.66
36047938	36383821	9,954.26	477.80
TOTAL		**36,719.68**	**1,762.54**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319508227
INVOICE DATE: 11/5/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
NOV 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR OCT 2020 REFERENCE EXHIBIT I	$590,464.69

PAYMENT DUE BY 11/20/20 AMOUNT DUE $590,464.69

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 11/20/20

INVOICE STATEMENT NO: 9319508227
0
11/5/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

OCTOBER 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(15,842)

ACTUAL COST:

WESTERN RECEIPTS	15,842
FUEL COSTS - WESTERN	$565,337.61
HANDLING COST - WESTERN	11,311.19
LIME CHARGES	6,907.62
UREA CHARGES	4,171.10
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	37,621
PRICE PER GALLON	$1.3301
% OF TOTAL BURN:	5.47%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

OCTOBER 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(15,842)
ENDING BALANCE	(2,360)
CONTRACTUAL BALANCE	13,482
OCTOBER RECEIPTS	15,842

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

OCTOBER 2020 ACTUAL

ACTUAL FUEL COST

			WESTERN	
FUEL			$565,337.61	
HANDLING			$11,311.19	
LIME CHARGES			6,907.62	
UREA CHARGES			4,171.10	
ACT. CARB.			-	
TONS (WET)		15,842		
UNIT PRICE		$37		
	TOTAL		$587,727.52	$587,727.52
	AUX GEN FUEL COST (EXHIBIT IIA)			$2,737.17
	TOTAL INVOICE TO MPPA			$590,464.69

Fuel	Fuel Hdlg	
$568,074.78	$22,389.91	$590,464.69
1510-0000-000-02	5011-0000-001-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

OCTOBER 2020 ACTUAL

FUEL OIL USED IN GENERATION	37,621	GALS
PRICE PER GALLON	$1.3301	
TOTAL	$50,039.69	
MPPA % OF BURN	0.0547	
MPPA AUXILIARY FUEL COST	$2,737.17	

CAMPBELL UNIT 3 FUEL BILLING JOURNAL ENTRY - MPPA

	Debits	Credits	
1462000	**$590,464.69**		
1697760		**$587,727.52**	coal
1697700		**$2,737.17**	fuel oil
1697700			
TOTAL	$590,464.69	$590,464.69	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319548439
INVOICE DATE: 11/9/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
NOV 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF OCT 2020	$186,461.60

PAYMENT DUE BY 11/20/20

AMOUNT DUE $186,461.60

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 11/20/20

INVOICE STATEMENT NO: 9319548439

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
OCT 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses	
I	Production & Transmission Expenses	$95,613.48	See Sched I
II	Gen Office Eng & Suprv - Allocation	$12,167.71	See Sched II
III	Employee Benefits	$2,050.92	**9260-0000-001-02**
IV	Payroll Taxes	$5,774.13	**4083-0000-001-02**
V	Admin & General Expenses	$10,485.47	See Sched V-A
VI	Insurance	$60,369.89	**9240-0000-001-2**
	Total	$186,461.60	

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
OCT 2020 ACTUAL

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**9,942.56**	$192,668.03	$14,468.62	$207,136.65
501	**5011-0000-001-02**	**2,926.51**	$278,202.28	($217,233.42)	$60,968.86
502	**5020-0000-001-02**	**20,960.15**	$396,703.78	$39,965.95	$436,669.73
505	**5050-0000-001-02**	**8,987.17**	$186,007.88	$1,224.90	$187,232.78
506	**5060-0000-001-02**	**3,757.01**	$37,915.09	$40,355.98	$78,271.07
510	**5100-0000-001-02**	**4,848.07**	$91,294.82	$9,706.65	$101,001.47
511	**5110-0000-001-02**	**5,520.70**	$28,418.28	$86,596.34	$115,014.62
512	**5120-0000-001-02**	**34,167.87**	$278,234.91	$433,595.64	$711,830.55
513	**5130-0000-001-02**	**2,667.53**	$43,979.42	$11,594.22	$55,573.64
514	**5140-0000-001-02**	**1,835.91**	$18,803.88	$19,444.26	$38,248.14
Total		95,613.48	$1,552,228.37	$439,719.14	$1,991,947.51
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$74,506.96	$21,106.52	$95,613.48

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
OCT 2020 ACTUAL

Campbell 3 GO - E&S - Production		253,493.94	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$12,167.71	
BILL MPPA		**$12,167.71**	
	5000-0000-001-02	**6,083.85**	
	5060-0000-001-02	**$6,083.86**	
		12,167.71	
GO E&S Labor =	$91,138.45	4.80%	$4,374.65

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,540.27	99	1	1,537.47	
BTS-Stm Exp	180250	182,204.03	28	72	49,676.23	
Fossil Train	180223	39,500.38	82	18	32,287.25	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	30,249.26	26	74	7,637.50	
		253,493.94			91,138.45	

N:\New Projects.2020\C3\2020 CECo Invoices\10 2020 CECo O&M

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
OCT 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,757.68**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**943.69**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**2,956.90**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**765.44**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**1,059.03**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**83.88**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**62.91**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**1,352.63**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**20.97**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**482.33**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		10,485.46	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$218,447		
Indirect Pen & Ben =	$218,447	0.80%	$1,748
A & G Salaries =	$218,447	26.30%	$57,452

MICHIGAN PUBLIC POWER AGENCY
ATTN: GENERAL MANAGER
809 CENTENNIAL WAY
LANSING, MI 48917

INVOICE STATEMENT NO: 9319783624
INVOICE DATE: 12/16/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DESCRIPTION	CHARGES	
DEC 2020	ACTUAL CONSTRUCTION EXPENDITURES DURING THE MONTH OF NOV 2020	$50,332.55	**1066-2000-000-02**
	RETIREMENT EXPENDITURES DURING THE MONTH OF NOV 2020	$1,517.24	**1086-2000-001-02**
	CREDIT FOR ADVANCE PAYMENT FOR ESTIMATED CONSTRUCTION EXP. FOR THE MONTH OF NOV 2020	0.00	

PAYMENT DUE BY 1/15/21 AMOUNT DUE $51,849.79

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 1/15/21

INVOICE STATEMENT NO: 9319783624

MICHIGAN PUBLIC POWER AGENCY

12/16/20

CONSUMERS ENERGY Schedule II
MPPA CONSTRUCTION BILLING SUMMARY
FOR THE MONTH OF NOVEMBER 2020

CONSTRUCTION

Superior Order	Sub Order	Total Cost	MPPA Share
3000120	3000120		0.00
3008419	3008419		0.00
3009044	3009044		0.00
3011628	3011628		0.00
3011846	3011846		0.00
3012381	3012381		0.00
3012919	3012919		0.00
3012980	3012980		0.00
3013163	3013163		0.00
3013378	3013378		0.00
3013438	3013438		0.00
3013598	3013598		0.00
3013878	3013878		0.00
3013998	3013998		0.00
3014301	3014301	37.08	1.78
3014541	3014541		0.00
3014582	3014582	(1,430.26)	(68.65)
3014700	3014700		0.00
3014808	3014808		0.00
3014858	3014858		0.00
3015026	3015026		0.00
3015030	3015030		0.00
3015039	3015039	70.09	3.36
3015092	3015092	16,653.44	799.37
3015098	3015098	5,791.30	277.98
3015182	3015182	14,193.00	681.26
12207242	12518451		0.00
13759003	15186473		0.00
14646216	16878135		0.00
21840033	21840037		0.00
21848482	22497755		0.00
24226871	24368556		0.00
24777421	25065937	4,197.16	201.46
24851767	25065938		0.00
27741169	28020389		0.00
27741171	28020391		0.00
28411874	28966093		0.00
28919497	29084950		0.00
29090639	29303622		0.00
29255064	29255064	918.43	44.08
29342833	29649993	6,300.61	302.43
29648629	29952931	10,213.40	490.24
29342487	30136462		0.00
29344915	30136463		0.00
29809509	30136466		0.00
29453415	30179488		0.00
30447106	30447106		0.00
30949426	31464867		0.00
30461542	31464878		0.00
31593775	31903546	145.80	7.00
31594191	31903557		0.00
31672277	31903077		0.00
31732508	31903079		0.00
31768429	32014366		0.00
31768432	32014370	883.94	42.43
31672365	32061343		0.00
31594199	32182462		0.00
31769040	32182464	1,364.14	65.48
31769228	32547749	2,269.74	108.95
32080550	32547750		0.00
31630779	32686481	732.92	35.18
32762652	33432977		0.00
31338989	33434098		0.00
33365304	33900652		0.00
33470359	33947104	(23,915.15)	(1,147.93)
29535933	33947106		0.00
32762651	34070925		0.00
34066749	34382195		0.00
33377496	34383018		0.00
31630778	34484167	1,480.88	71.08
34066657	34484358	13,119.60	629.74

34275673	34640501		0.00
34498210	34640502	2,278.80	109.38
34646163	34646163	74,138.87	3,558.67
34275231	34769326	13,133.13	630.39
34536864	34769328	25,479.13	1,223.00
34616096	34770035	973.68	46.74
34066741	34929637		0.00
34688256	34929638		0.00
34763474	34929801	2,167.35	104.03
34763477	34947989		0.00
34763479	34947990	2,817.68	135.25
34550414	34949236		0.00
34686197	34949843		0.00
34815508	35084575	151,900.17	7,291.21
34686388	35084577		0.00
35117725	35247545	373.70	17.94
34238934	35250267		0.00
35385384	35404444		0.00
34756522	35418570		0.00
34815514	35418571		0.00
34857040	35418573		0.00
35098247	35418574		0.00
35098389	35418575		0.00
35170052	35418576	2,709.36	130.05
35588963	35588964		0.00
35072889	35607300		0.00
35170056	35607304		0.00
35288776	35607306		0.00
35289301	35607307		0.00
35624240	35624240		0.00
35098589	35637415		0.00
33916264	35702594		0.00
34923179	35702596		0.00
35076276	35702597		0.00
35274355	35702598		0.00
35275332	35702599		0.00
35368742	35703040		0.00
35472893	35703042		0.00
34793531	35869041		0.00
35385262	35869042		0.00
34923174	35973388		0.00
35724931	35973389		0.00
35841415	35973395		0.00
35036769	35976325		0.00
36097009	36097009	124.00	5.95
35934141	36098425	(476.26)	(22.86)
35988062	36180715		0.00
35988062	36221401	1,265.78	60.76
35420948	36271040	355,783.33	17,077.60
36095379	36271041		0.00
36096196	36271042	188.66	9.06
36204335	36383347		0.00
36308739	36383348		0.00
36047938	36383821		0.00
36347629	36562360		0.00
36162805	36562367	19,606.51	941.11
36309136	36562369	13,942.83	669.26
36164627	36711154	1,265.35	60.74
36209181	36711157		0.00
36262102	36711320		0.00
36347623	36711321		0.00
36370395	36711323		0.00
36557894	36711324		0.00
36564435	36711325		0.00
36464982	36722386		0.00
36147109	36887938		0.00
36675972	36890775	2,000.60	96.03
36693696	36890776	19,279.93	925.44
36744474	36890777	97,184.44	4,664.85
36467356	36904335		0.00
36524623	36987123	26,842.52	1,288.44
36525328	36987124		0.00
36676472	36987126	250.11	12.01
36746601	36987129	1,687.46	81.00
36468351	36997251	598.25	28.72
36798266	36997253	50,737.62	2,435.41
36700977	37120123	71,416.32	3,427.98
36150435	37852662		0.00
36745403	37961780	8,722.94	418.70
37017484	37961782	49,175.82	2,360.47

TOTAL	**1,048,594.20**	**50,332.55**

RETIREMENTS (Cost of Removal & Salvage)

Retire S.O. #	Retire Sub Order		MPPA Share
21840037	21840037		
28919497	29084950		
29255064	29255064	50.84	2.44
29809509	30136466		
29453415	30179488		
30447106	30447106		
31594191	31903557		
31672365	32061343		
31630779	32686481		
29535933	33947106		
33377496	34383018		
34646163	34646163	17,938.96	861.07
34536864	34769328		
34793531	35869041		
36096196	36271042	21.05	1.01
36047938	36383821	13,598.40	652.72
TOTAL		**31,609.25**	**1,517.24**

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING, MI 48917

INVOICE STATEMENT NO: 9319698771
INVOICE DATE: 12/3/20

FOR INQUIRIES CALL:
(517) 788-0337

DATE	DESCRIPTION	CHARGES
DEC 2020	FUEL COSTS RELATED TO MAINTEANCE OF THE STOCKPILE FOR NOV 2020 REFERENCE EXHIBIT I	$555,713.66

PAYMENT DUE BY 12/20/20 AMOUNT DUE $555,713.66

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

WIRE PAYMENT TO:
JP MORGAN CHASE
ABA # for ACH 072000326
FOR CREDIT TO CONSUMERS
ENERGY ACCT NO 11310

MICHIGAN PUBLIC POWER AGENCY

PAYMENT DUE BY 12/20/20

INVOICE STATEMENT NO: 9319698771
0
12/3/20

MAINTENANCE OF FUEL STOCKPILE COST
DATA INPUT
MPPA

NOVEMBER 2020 ACTUAL

COAL INVENTORY:

BEGINNING BALANCE WESTERN	13,482
ADJUSTMENTS	0
WESTERN BURN:	(14,943)

ACTUAL COST:

WESTERN RECEIPTS	14,943
FUEL COSTS - WESTERN	$536,872.10
HANDLING COST - WESTERN	9,518.69
LIME CHARGES	5,606.05
UREA CHARGES	2,005.28
ACTIVATED CARBON	-

AUX GEN FUEL COSTS:

FUEL OIL USED:	24,642
PRICE PER GALLON	$1.3357
% OF TOTAL BURN:	5.20%

EXHIBIT I

MPPA CAMPBELL 3 COAL INVENTORY

NOVEMBER 2020 ACTUAL

(WET TONS)

	WESTERN
BEGINNING BALANCE	13,482
ADJUSTMENTS	0
BURN	(14,943)
ENDING BALANCE	(1,461)
CONTRACTUAL BALANCE	13,482
NOVEMBER RECEIPTS	14,943

EXHIBIT II

MPPA CAMPBELL 3 FUEL INVENTORY

NOVEMBER 2020 ACTUAL

ACTUAL FUEL COST

		WESTERN	
FUEL		$536,872.10	
HANDLING		$9,518.69	
LIME CHARGES		5,606.05	
UREA CHARGES		2,005.28	
ACT. CARB.		-	
TONS (WET)	14,943		
UNIT PRICE	$37		
TOTAL		$554,002.12	$554,002.12
AUX GEN FUEL COST (EXHIBIT IIA)			$1,711.54
TOTAL INVOICE TO MPPA			$555,713.66

Fuel		Fuel Hdlg	
	$538,583.64	$17,130.02	$555,713.66
1510-0000-000-02		5011-0000-001-02	

EXHIBIT IIA

MPPA CAMPBELL 3 FUEL INVENTORY

AUXILIARY FUEL COST

NOVEMBER 2020 ACTUAL

FUEL OIL USED IN GENERATION	24,642	GALS
PRICE PER GALLON	$1.3357	
TOTAL	$32,914.32	
MPPA % OF BURN	0.052	
MPPA AUXILIARY FUEL COST	$1,711.54	

MICHIGAN PUBLIC POWER AGENCY

ATTN: GENERAL MANAGER
809 CENTENNIAL WAY

LANSING MI 48917

INVOICE STATEMENT NO: 9319739886
INVOICE DATE: 12/8/20

FOR INQUIRIES CALL:
*(517)788-0337

DATE	DOC #	DESCRIPTION	CHARGES
DEC 2020		ACTUAL OPERATING COSTS FOR CAMPBELL #3 DURING THE MONTH OF NOV 2020	$114,126.72

PAYMENT DUE BY 12/20/20

AMOUNT DUE $114,126.72

PLEASE DETACH THIS STUB AND RETURN IT WITH YOUR PAYMENT

SEND PAYMENT TO:
CONSUMERS ENERGY
LANSING, MI 48937-0001

PAYMENT DUE BY 12/20/20

INVOICE STATEMENT NO: 9319739886

MICHIGAN PUBLIC POWER AGENCY

CONSUMERS ENERGY COMPANY
CAMPBELL UNIT 3
SUMMARY OF OPERATION & MAINTENANCE COSTS
NOV 2020 ACTUAL

Schedule	Item	MPPA O&M Expenses
I	Production & Transmission Expenses	$84,507.29
II	Gen Office Eng & Suprv - Allocation	$12,973.13
III	Employee Benefits	$1,987.62
IV	Payroll Taxes	$5,595.91
V	Admin & General Expenses	$9,062.77
VI	Insurance	$0.00
	Total	$114,126.72

Schedule I

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of Production Expenses
NOV 2020 ACTUAL

FERC Account			Labor	Other	Total
500	**5000-0000-001-02**	**9,907.45**	$191,237.20	$15,167.97	$206,405.17
501	**5011-0000-001-02**	**6,852.69**	$301,632.18	($158,867.90)	$142,764.28
502	**5020-0000-001-02**	**22,441.69**	$413,665.35	$53,869.77	$467,535.12
505	**5050-0000-001-02**	**9,277.70**	$192,405.64	$879.85	$193,285.49
506	**5060-0000-001-02**	**3,586.53**	$38,559.80	$36,159.65	$74,719.45
510	**5100-0000-001-02**	**5,206.43**	$101,212.07	$7,255.20	$108,467.27
511	**5110-0000-001-02**	**5,232.93**	$32,908.26	$76,111.21	$109,019.47
512	**5120-0000-001-02**	**16,112.69**	$163,719.87	$171,961.18	$335,681.05
513	**5130-0000-001-02**	**3,092.44**	$43,922.96	$20,502.83	$64,425.79
514	**5140-0000-001-02**	**2,796.74**	$19,512.79	$38,752.69	$58,265.48
Total		**84,507.29**	$1,498,776.12	$261,792.45	$1,760,568.57
MPPA OWNERSHIP %			4.80%	4.80%	4.80%
MPPA SHARE			$71,941.25	$12,566.04	$84,507.29

Schedule I-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Production Expenses
NOV 2020 ACTUAL

FERC Account	Cost Centers	Labor	Other	Total
500	110016	19,027.22	8,915.13	27,942.35
506	110017	24,052.44	1,135.84	25,188.28
510	110018	12,507.31	2,547.74	15,055.05
511	110267	31,918.86	76,111.21	108,030.07
512	110268	142,094.38	171,961.18	314,055.56
513	110269	40,474.19	20,502.83	60,977.02
514	110270	17,307.83	38,752.69	56,060.52
500	110271	166,015.60	6,078.15	172,093.75
510	110272	84,782.22	4,524.85	89,307.07
501	110273	301,632.18	39,438.15	341,070.33
501	110273	0.00	(198,306.05)	(198,306.05)
502	110274	413,665.35	53,869.77	467,535.12
505	110275	192,405.64	879.85	193,285.49
506	110276	14,507.36	35,023.81	49,531.17
502	110714	0.00	0.00	0.00
512	110715	21,625.49	0.00	21,625.49
511	110842	0.00	0.00	0.00
505	110850	0.00	0.00	0.00
511	110864	989.40	0.00	989.40
513	110865	3,448.77	0.00	3,448.77
514	110866	2,204.96	0.00	2,204.96
502	140016	0.00	0.00	0.00
501	140745	0.00	0.00	0.00
501	140921	0.00	0.00	0.00
500	111635	0.00	0.00	0.00
510	111636	0.00	0.00	0.00
500	111680	2,356.38	2.72	2,359.10
500	111694	0.00	0.00	0.00
500	122346	84.52	10.65	95.17
510	122347	169.06	21.29	190.35
500	180036	3,753.48	161.32	3,914.80
510	180037	3,753.48	161.32	3,914.80
501 Aux Fuel		0.00	0.00	0.00
	TOTAL	$1,498,776.12	$261,792.45	$1,760,568.57

Schedule II

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Summary of GO Engineering & Supervision
NOV 2020 ACTUAL

Campbell 3 GO - E&S - Production		270,273.52	
MPPA OWNERSHIP %		4.80%	
MPPA - GO E&S SHARE		$12,973.13	
BILL MPPA		**$12,973.13**	
	5000-0000-001-02	**6,486.56**	
	5060-0000-001-02	**$6,486.57**	
		12,973.13	
GO E&S Labor =	$93,867.45	4.80%	$4,505.64

		Campbell 3	Labor	non-Labor	Labor	non-Labor
Bonus	111067	-			-	
Sys Prot	122258	1,410.40	99	1	1,408.26	
BTS-Stm Exp	180250	163,466.22	29	71	47,243.13	
Fossil Train	180223	56,250.72	59	41	32,939.48	
Maj Maint	111390	0.00			0.00	
Eng Admin St Exp	180119	0.00			0.00	
End Admin Exp	180120	0.00			0.00	
EICP BTL	111735	0.00			0.00	
Security	141065	49,146.18	25	75	12,276.58	
		270,273.52			93,867.45	

Schedule III

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Employee Pension & Benefits
NOV 2020 ACTUAL

Production Labor (Schedule I)	$1,498,776.12
E&S Labor (Schedule II)	$93,867.45
Total Labor	$1,592,643.57
Pension & Benefits Loading Rate	x 2.60%
Penison & Benefits Expense	$41,408.73
MPPA OWNERSHIP %	4.80%
MPPA SHARE	$1,987.62

Schedule IV

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Payroll Taxes
NOV 2020 ACTUAL

Production Labor (Schedule I)		$1,498,776.12
E&S Labor (Schedule II)		$93,867.45
Total Labor		$1,592,643.57
Payroll Tax Loading Rate	x	7.32%
Payroll Tax		$116,581.51
MPPA OWNERSHIP %		4.80%
MPPA SHARE		$5,595.91

Schedule V

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Administrative and General Expenses
NOV 2020 ACTUAL

Production Expense	
Schedule I	$1,760,568.57
Less: A/C 501	($142,764.28)
	$1,617,804.29
GO Engineering & Supervision	
Schedule II	$270,273.52
Total	$1,888,077.81
A&G %	10.00%
Allocated A&G Expense	$188,807.78
MPPA OWNERSHIP %	4.80%
MPPA SHARE	$9,062.77

Schedule V-A

CONSUMERS ENERGY COMPANY
Campbell Unit 3
Allocation of A&G Expenses
NOV 2020 Actual

Account			Amount	Less	Billing CR Addbacks	Balance	% of Total
920	**9200-0000-001-02**	**2,383.51**	43,323,913.00	(16,603,380.00)	52,092.00	$26,772,625	26.30%
921	**9210-0000-001-02**	**815.65**	11,386,221.00	(2,579,316.00)	336,146.00	$9,143,051	9.00%
922	**9220-0000-001-02**	**-**	(19,182,696.00)	19,182,696.00		$0	0.00%
923	**9230-0000-001-02**	**2,555.70**	28,339,550.00	0.00	242,051.00	$28,581,601	28.20%
924	**9240-0000-001-02**	**661.58**	3,113,930.00	4,211,057.00	78,283.00	$7,403,270	7.30%
925	**9250-0000-001-02**	**915.34**	10,071,322.00	0.00	124,077.00	$10,195,399	10.10%
926	**9260-0000-001-02**	**72.50**	6,760,213.00	(6,106,476.00)	178,964.00	$832,701	0.80%
928	**9280-0000-001-02**	**54.38**	572,500.00	0.00	1,647.00	$574,147	0.60%
930	**9300-0000-001-02**	**1,169.10**	13,037,141.00	0.00	68,755.00	$13,105,896	12.90%
931	**9310-0000-001-02**	**18.13**	166,781.00	0.00	2,219.00	$169,000	0.20%
935	**9350-0000-001-02**	**416.88**	4,577,531.00	0.00	53,021.00	$4,630,552	4.60%
		9,062.77	$102,166,406	($1,895,419)	$1,137,255	$101,408,242	100.0%

Indirect Pension & Benefits % =		0.80%	
Allocated A & G =	$188,808		
Indirect Pen & Ben =	$188,808	0.80%	$1,510
A & G Salaries =	$188,808	26.30%	$49,656

Question:

9. Please provide for each month in 2020 the Michigan Public Power Agency share of generation from Campbell Unit 3, and the amounts billed to Michigan Public Power Agency for energy and for capacity each month in 2020

Response:

The Michigan Public Power Agency ("MPPA") share of generation in kilowatt-hours ("kWh") from Campbell Unit 3 for each month in 2020 is as follows:

Jan	39,342,000
Feb	26,959,000
Mar	28,860,000
Apr	22,444,000
May	10,995,000
Jun	26,842,000
Jul	20,108,000
Aug	28,930,000
Sep	27,221,000
Oct	28,579,000
Nov	27,340,000
Dec	20,124,000

MPPA is billed for their share of total plant costs which in turn gives them the right to their portion of energy and capacity from the facility. The amounts billed to MPPA for each month in 2020 are as follows:

Jan	$1,090,832.89
Feb	$854,366.76
Mar	$696,719.88

Apr	$790,842.09
May	$661,083.64
Jun	$678,815.84
Jul	$522,754.35
Aug	$580,642.78
Sep	$767,438.57
Oct	$730,206.65
Nov	$839,126.64
Dec	$721,690.17

KEITH G. TROYER
August 3, 2021

EGI Contracts & Settlements

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

Case No.: U-20526
Exhibit No.: A-17 (JLR-1)
Page: 1 of 1
Witness: JLRickard
Date: March 2021

PURCHASED POWER AND COGENERATION - ENERGY AND EXPENSE
TOTAL 2020

Line	(a) Company Name	(b) MWH	(c) Variable Energy $	(d) Admin Fees $	(e) Net Energy $	(f) Fixed Energy $	(g) Capacity $	(h) Total $	(i) Variable Energy Cost $/Mwh	(j) Total Cost $/Mwh
1	Bay Windpower[1]	2,534	101,701	0	101,701	0	10,522	112,223	40.14	44.29
2	Black River	4,854	369,137	(4,382)	364,755	0	5,744	370,499	75.14	76.32
3	City of Beaverton	3,415	273,221	(3,415)	269,806	0	(9,572)	260,234	79.00	76.19
4	City of Midland	1,469	22,743	(4,505)	18,238	0	0	18,238	12.41	12.41
5	Commonwealth Irving	2,203	71,710	(1,709)	70,001	0	62,021	132,022	31.78	59.93
6	Commonwealth Labarge	4,445	239,405	0	239,405	0	42,089	281,494	53.86	63.33
7	Commonwealth Middleville	686	23,987	(679)	23,308	0	26,635	49,944	33.97	72.80
8	C & C Energy LLC (C&C Electric 2)	16,889	889,178	(16,889)	872,290	0	0	872,290	51.65	51.65
9	Elk Rapids 2	1,972	139,404	(1,972)	137,432	0	38,124	175,556	69.68	89.01
10	Good Fruit Storage	169	6,202	0	6,202	0	19,882	26,083	36.61	153.99
11	Granger - Seymour	5,105	147,011	(5,105)	141,906	32,487	217,345	391,738	27.80	76.73
12	Great Lake Tissue	224	5,715	(224)	5,491	0	0	5,491	24.46	24.46
13	Grenfell Hydro	1,872	101,182	0	101,182	0	15,783	116,966	54.05	62.48
14	Kleber Hydro	5,923	385,845	(5,915)	379,930	0	0	379,930	64.15	64.15
15	MAHLE Engine Components	5	96	(4,505)	(4,409)	0	0	(4,409)	(897.58)	(897.58)
16	Michiana Hydro	274	23,117	(274)	22,843	0	24,296	47,139	83.44	172.19
17	Michigan State University	14,842	367,057	(2,328)	364,729	0	0	364,729	24.57	24.57
18	NANR - Rathbun[2]	4,765	225,696	0	225,696	0	68,394	294,090	47.37	61.72
19	Otsego Paper	13,310	290,931	(13,310)	277,621	0	0	277,621	20.86	20.86
20	STS Cascade	13,490	733,357	711	734,068	0	117,900	851,969	54.41	63.15
21	STS Fallasburg	1,544	86,196	140	86,336	0	53,925	140,261	55.91	90.82
22	STS Ada	4,392	133,843	(4,392)	129,451	0	135,529	264,980	29.47	60.33
23	Tower Hydro	1,795	117,081	(1,795)	115,287	0	0	115,287	64.24	64.24
24	Venice Park	17,771	945,365	(17,771)	927,594	0	0	927,594	52.20	52.20
25	White's Bridge	4,719	400,364	(4,719)	395,645	0	(3,485)	392,160	83.83	83.10
26	Ada Cogeneration	143,505	4,077,185	(24,000)	4,053,185	1,549,169	9,728,173	15,330,526	28.24	106.83
27	Adrian Energy	12,156	422,948	(12,217)	410,731	0	530,388	941,119	33.79	77.42
28	Boyce Hydro	11,124	458,908	0	458,908	0	245,317	704,225	41.25	63.31
29	Cadillac Renewable	49,655	1,317,649	(8,006)	1,309,644	723,183	4,525,485	6,558,311	26.37	132.08
30	Entergy Palisades	6,898,204	76,297,844	0	76,297,844	0	326,563,665	402,861,508	11.06	58.40
31	Filer City	512,995	17,770,750	(24,000)	17,746,750	0	22,902,768	40,649,518	34.59	79.24
32	C & C Energy LLC (C&C Electric 1)	11,506	330,400	(11,466)	318,933	73,034	489,338	881,306	27.72	76.59
33	Genesse Power Station	90,239	2,390,455	(24,000)	2,366,455	1,792,012	12,839,688	16,998,155	26.22	188.37
34	Granger - Byron Center	18,565	923,265	(18,550)	904,714	203,225	270,408	1,378,347	48.73	74.24
35	Granger - Grand Blanc	21,754	808,962	(21,387)	787,575	104,967	900,488	1,793,030	36.20	82.42
36	Granger - Ottawa	35,516	1,206,090	(34,671)	1,171,419	123,560	1,714,240	3,009,219	32.98	84.73
37	Granger - Pinconning	23,098	866,988	(23,269)	843,718	111,057	844,388	1,799,164	36.53	77.89
38	Grayling	66,304	1,900,587	(25,363)	1,875,224	719,099	4,567,182	7,161,505	28.28	108.01
39	Hillman Limited	109,647	4,307,164	(45,145)	4,262,019	0	3,064,076	7,326,095	38.87	66.82
40	Kent County	101,188	6,390,685	(55,309)	6,335,377	0	1,849,877	8,185,254	62.61	80.89
41	Michigan Power Limited	1,064,554	37,063,584	(24,000)	37,039,584	0	40,087,322	77,126,907	34.79	72.45
42	Michigan Wind 1, LLC (PPA 1)[3]	139,350	2,951,733	0	2,951,733	0	298,760	3,250,493	21.18	23.33
43	Michigan Wind 1, LLC (PPA 2)	29,932	1,519,482	(28,839)	1,490,643	0	0	1,490,643	49.80	49.80
44	North American Resources (Peoples)	23,836	682,132	(24,213)	657,919	149,951	1,010,300	1,818,170	27.60	76.28
45	Viking - Lincoln	143,096	5,735,257	(45,145)	5,690,112	0	2,766,681	8,456,793	39.76	59.10
46	Viking - McBain	138,797	5,562,968	(45,145)	5,517,823	0	2,900,845	8,418,668	39.75	60.65
47	WM Renewable Energy	12,735	364,132	(12,721)	351,410	80,168	517,254	948,832	27.59	74.50
48	MCV	6,110,093	119,945,647	(24,000)	119,921,647	68,613,660	110,172,469	298,707,775	19.63	48.89
49	**Subtotal**	15,896,520	299,394,360	(624,487)	298,769,874	74,275,569	549,614,246	922,659,689	18.79	58.04
50	Biomass Merchant Plant	0	0	0	11,874,762	0	0	11,874,762	0.00	0.00
51	**TOTAL**	15,896,520	299,394,360	(624,487)	310,644,636	74,275,569	549,614,246	934,534,451	19.54	58.79

[1] Includes $641 related to RRP.
[2] Includes ($660) related to RRP.
[3] Includes $7,597 related to RRP.

Default MOPR Floor Offer Prices for New Generation Capacity Resources

Market Implementation Committee
March 11, 2020

Default MOPR Floor Price for New Resources

- Based on Net Cost of New Entry (“CONE”) for relevant technology type
- Net CONE = Gross CONE – Net E&AS revenue
  - Gross CONE: levelized annual cost to construct a new resource plus annual fixed operation and maintenance costs
  - Net E&AS: expected energy and ancillary service market revenues
- PJM has developed preliminary Gross CONE values for the following generation technology types:
  - CT, CC, Coal, Nuclear, Solar Tracking, Solar Fixed, Onshore Wind, Offshore Wind, Battery Storage, Demand Response (generation backed)

Updates

- Investigated alternative sources for renewables
  - NREL solar data is in $/kW$_{DC}$, multiply by 1.3 ILR to convert to $/kW$_{AC}$
- Split solar resource category into “tracking” and “fixed”
  - Fixed costs (94% of tracking, based on LBNL and IHS cost ratios)
  - Applied 60% capacity value for tracking, 42% for fixed
- Increased Onshore Wind capacity value from 14.7% to 17.6%
- Added resource category Demand Response (generation backed)
- Completed E&AS methodologies and Net CONE values

Appendix provides E&AS methods, resource links and a comparison of capital costs from the various data sources

Table 1 – Total Capital Cost and Fixed O&M Cost

Resource Type	Technology Description	Source of Information	Fixed O&M ($/kW-year)	Installed Capital Cost ($/kW)
Nuclear	2 x Westinghouse AP1000 Pressurized Water Reactor (2,156 MW)	EIA (Case 11)	122	6,041
Coal	Ultra-Super Critical Coal (650 MW)	EIA (Case 1)	41	3,676
Combined Cycle	2x1 GE Frame 7HA with evaporative cooling and SCR (1,152 MW)	Quadrennial Review	24	874
Combustion Turbine	GE Frame 7HA CT with evaporative cooling, SCR, dual fuel (352 MW)	Quadrennial Review	17	875
Solar PV - Tracking	Single-axis tracking (150 MW AC)	EIA (Case 24)	15	1,313
Solar PV - Fixed	Fixed-tilt (100 MW AC)	EIA, LBNL, IHS	14	1,234
Onshore Wind	17 x 2.8 MW WTGs (50 MW)	EIA (Case 21)	35	1,677
Offshore Wind	40 x 10 WTGs, 100’ depth (400 MW)	EIA (Case 22)	110	4,375
Battery Storage	50 MW utility scale, Li, 200 MWh rating	EIA (Case 18)	25	1,389
Demand Response	2 MW RICE, ultra-low sulfur diesel	*TBA*	*TBA*	*TBA*

Financial Assumptions

Financial assumptions developed during 2018 Quadrennial Review used to determine Gross CONE from the installed capacity costs and fixed costs

Financial Assumptions	
Expected Life	20 Years
Debt Ratio	55.0%
Debt Rate	6.0%
Equity Rate	13.0%
Total Tax Rate	27.7%
ATWACC	8.2%
Inflation Rate	2.2%

Table 2 – Gross CONE Values

Resource Type	Fixed O&M ($/kW-year)	Installed Capital Cost ($/kW)	Gross CONE ($/MW-Day) (*Nameplate*)
Nuclear	122	6,041	2,000
Coal	41	3,676	1,068
Combined Cycle	24	874	320
Combustion Turbine	17	875	294
Solar PV (Tracking)	15	1,313	290
Solar PV (Fixed)	14	1,234	271
Onshore Wind	35	1,677	420
Offshore Wind	110	4,375	1,155
Battery Storage (4h.)	25	1,389	532

Gross CONE reflects 100% bonus depreciation and 30% Investment Tax Credit for solar and wind

Table 3 – Gross CONE Value Comparison

Resource Type	NREL - Gross CONE ($/ICAP MW-Day) (*Nameplate*)	EIA - Gross CONE ($/ICAP MW-Day) (*Nameplate*)	Difference ($/ICAP MW-Day) (*Nameplate*)
Nuclear	2,062	2,000	62
Coal	1,118	1,068	50
Combined Cycle	320	320	N/A
Combustion Turbine	294	294	N/A
Solar PV (Tracking)	297	290	7
Solar PV (Fixed)	279	271	8
Onshore Wind	405	420	-15
Offshore Wind	999	1,155	-156
Battery Storage (4h.)	473	532	-59

PJM intends to use the EIA-based values

Net E&AS Offset Revenues

- FERC order requires that net E&AS offset revenues be determined for each transmission zone
- A proposed method for estimating the net energy market revenues for each technology type is described in the Appendix
- Proposed method would use historical zonal LMPs from three most recent calendar years to develop zonal Net E&AS values
- Table 4 provides Net CONE values determined using the Gross CONE and Net E&AS Revenue Offset

Table 4 – Average Zonal Net CONE – Capacity Value Basis

Resource Type	Gross CONE ($/MW-Day) (*Nameplate*)	Average Zonal E&AS Revenue Offset ($/MW-Day) (*Nameplate*)	Net CONE ($/MW-Day) (*Nameplate*)	Capacity Value (Percent of *Nameplate*)	Net CONE ($/ICAP MW-Day)
Nuclear	2,000	517	1,483		**1,483**
Coal	1,068	43	1,025		**1,025**
Combined Cycle	320	168	152		**152**
Combustion Turbine	294	48	246		**246**
Solar PV (Tracking)	290	185	105	60%	**175**
Solar PV (Fixed)	271	117	154	42%	**367**
Onshore Wind	420	240	180	17.6%	**1,023**
Offshore Wind	1,155	337	818	26%	**3,146**
Battery Storage	532	116	416	40%	**1,040**

Table 5 – Net CONE Values – ICAP Basis

Resource Type	Gross CONE ($/MW-Day) (*Nameplate*)	Avg. Zonal E&AS Revenue Offset ($/MW-Day) (*Nameplate*)	Net CONE ($/ICAP MW-Day)
Demand Response (Gen)	*TBA*	*TBA*	*TBA*
Energy Efficiency	N/A	N/A	46

Next Steps

- Continue coordinated refinement with IMM of estimates of costs and revenues
- Prepare and submit FERC filing by March 18

Appendix

Energy & Ancillary Services Offset Revenue

Resource Type	E&AS Methodology
Nuclear	Gross revenue determined by average annual LMP multiplied by annual energy output times class average equivalent availability factor. Net revenue determined by gross revenue minus cost to generate annual energy output (i.e. fuel cost, Variable O&M)
Coal	Simulated dispatch of a 650 MW coal unit (with heat rate of 9,250 BTU/kWh and variable operations and maintenance costs of $9.50/MWh) with the unit committed in profitable blocks of at least eight hours
Combined Cycle	Simulated dispatch with commitment for entire 16-hour period between HE 8 and HE 23 of each day if average LMP exceeds cost to generate (+10%) over this period. HR = 6,533 Btu/kWh, Variable O&M = $2.11/MWh
Combustion Turbine	Simulated dispatch with commitment for each 4-hour blocks between HE 8 and HE 23 of each day if average LMPs exceed cost to generate (+10%) in 2 of the 4 hours of each block. HR = 9,134 Btu/kWh, Variable O&M = $6.93/MWh
Solar PV (fixed & tracking)	Net energy market revenue estimate shall be determined using a solar resource model that provides the average output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the solar output level of each hour by the hourly LMP applicable for that hour with this product summed across all of the hours of an annual period. Two separate solar resource models are used, one model for a fixed panel resource and a second model for a tracking panel resource

Energy & Ancillary Services Offset Revenue

Resource Type	E&AS Methodology
Onshore Wind	Net energy market revenue estimate shall be determined using a wind resource model that provides the average output level, expressed as a percentage of nameplate rating, by hour of day (for each of the 24-hours of a day) and by calendar month (for each of the twelve months of a year). The annual energy market revenues are determined by multiplying the solar output level of each hour by the hourly LMP applicable for that hour with this product summed across all of the hours of an annual period
Offshore Wind	Average annual zonal LMP multiplied by annual wind energy output at 45% capacity factor
Battery Storage	Simulated dispatch with commitment for 4 highest LMP hours of a daily 24 hour period if average LMP of 4 lowest LMP hours exceeds (+120%) of average LMP of 4 highest LMP hours of the 24 hour period. Net revenues equal hourly MW output times hourly LMP for each discharging minus hourly MW consumed times hourly LMP when charging.
Demand Response (Gen)	Simulated dispatch of a 2 MW RICE unit (with heat rate of 9,660 BTU/kWh and variable operations and maintenance costs of $7.50/MWh) with the unit committed in any profitable hour

Capital Cost Sources

Source	Link
NREL: 2019 Annual Technology Baseline	atb.nrel.gov
Lazard: 2019 Levelized Cost of Energy & Storage	https://www.lazard.com/perspective/lcoe2019
	https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf
	https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf
EPA: IPM Platform 2018 Reference Case	https://www.epa.gov/airmarkets/documentation-ipm-platform-v6-november-2018-reference-case-all-chapters
EIA: 2020 Capital Cost Report	https://www.eia.gov/analysis/studies/powerplants/capitalcost/
PJM: Quadrennial Review	https://pjm.com/-/media/library/reports-notices/special-reports/2018/20180420-pjm-2018-cost-of-new-entry-study.ashx?la=en
LBNL: Utility Scale Solar – 2019 Edition	https://emp.lbl.gov/utility-scale-solar/
IHS: US Solar PV Capital Cost and LCOE Outlook	https://ihsmarkit.com/research-analysis/index.html

Installed Capital Costs from Different Sources ($/kW)

Technology	NREL 2022	Lazard 2019	EPA 2021	EIA 2019	PJM
Nuclear	6,506	6,900 – 12,200	5,644	6,041	6,041
Coal	3,944	3,000 – 6,250	3,580	3,676	3,676
Combined Cycle	894	700 – 1,300	1,081	1,084 (H)	874
Combustion Turbine	905	700 – 950	662	713 (7FA)	875
Solar PV (tracking)	1,343	1,100	1,034	1,313	1,313
Solar PV (fixed)	*1,262	900		1,234*	1,234
Onshore Wind	1,472	1,100 – 1,500	1,404	1,677	1,677
Offshore Wind	3,682	2,350 – 3,550	4,529	4,375	4,375
Battery Storage	1,157	898 – 1,874	N/A	1,389	1,389

** Fixed cost obtained from multiplying Tracking cost by 0.94*

Indiana Michigan Power:
2021 Integrated Resource Plan
Public Stakeholder Meeting #3A

July 27, 2021

Presented via GoToWebinar --> https://attendee.gotowebinar.com/register/2455690913279924

BOUNDLESS ENERGY℠

Agenda

Time		
9:30 a.m.	WELCOME AND SAFETY MOMENT	**Andrew Williamson**, I&M Director Regulatory Services
9:40 a.m.	MEETING GUIDELINES AND AGENDA	**Jay Boggs**, Siemens PTI
9:45 a.m.	IRP PROCESS AND TOOLS	**Peter Berini,** Siemens PTI
10:00 a.m.	INFORMATIONAL RFP'S	**Angelina Martinez,** Siemens PTI
10:15 a.m.	REFERENCE CASE DEVELOPMENT	**Peter Berini,** Siemens PTI, **Thijs Everts,** Siemens PTI
10:45 a.m.	BREAK	
11:00 a.m.	RESOURCE OPTIONS – SUPPLY SIDE	**Thijs Everts**, Siemens PTI
11:30 a.m.	LUNCH	
12:30 p.m.	RESOURCE OPTIONS – DSM	**Thijs Everts**, Siemens PTI, **Chad Burnett**, AEP Load Forecasting, **Jeffrey Huber**, GDS Associates
1:15 p.m.	SCENARIOS	**Peter Berini,** Siemens PTI
1:30 p.m.	STAKEHOLDER INTERACTION	**Art Holland**, Siemens PTI, **Jay Boggs**, Siemens PTI
2:00 p.m.	ADJOURN	

Exhibit AG-14
Case No. U-20530
August 24, 2021
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WELCOME AND SAFETY MOMENT

ANDREW WILLIAMSON | DIRECTOR, REGULATORY SERVICES

Safety Moment

INDIANA MICHIGAN POWER
An AEP Company

Exhibit AG-14
Case No. U-20530
August 24, 2021
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MEETING GUIDELINES

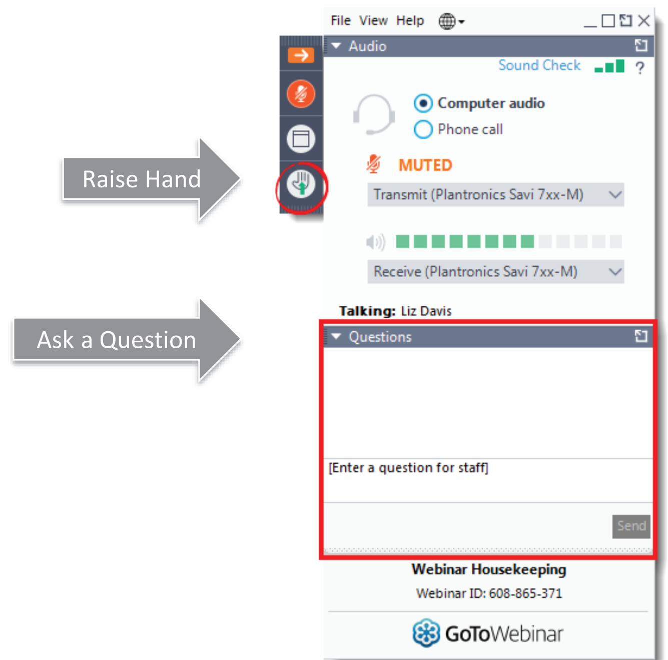
JAY BOGGS | SIEMENS PTI

Questions and Feedback

The purpose of today's presentation is to explain the IRP process and collect feedback from stakeholders. Stakeholder feedback will be posted on the I&M website IRP portal and will be considered as part of the Final IRP.

If you have a question about the IRP process during this presentation:

- Type your question in the Questions area of the GoToWebinar panel
- During the feedback and discussion portions of the presentations, please raise your hand via the GoToMeeting tool to be recognized
- Time permitting, we will address all questions and hear from all who wish to be heard
- Any questions that cannot be answered during the call will be addressed and posted on the website above



If you would like to make a comment or ask a question about the IRP process after the presentation has concluded:

- Please send an email to I&MIRP@aep.com
- Stay informed about future events by visiting the I&M IRP Portal located at www.indianamichiganpower.com/info/projects/IntegratedResourcePlan

Guidelines

1. Due to the number of participants scheduled to join today's meeting, all will be in a "listen-only" mode by default.

2. Please enter questions at any time into the GoToWebinar portal. Technical questions related to the GoToWebinar tool and its use will be addressed by the support staff directly via the chat feature.

3. Time has been allotted to answer questions related to the materials presented. Unanswered questions will be addressed after the presentation and posted in accordance with the Questions and Feedback slide.

4. At the end of the presentation, we will open-up the floor for "clarifying questions," thoughts, ideas, and suggestions.

5. Please provide feedback or questions on the Stakeholder Meeting #3A presentation within ten business days of the conclusion of the meeting.

Agenda

Time		
9:30 a.m.	WELCOME AND SAFETY MOMENT	**Andrew Williamson**, I&M Director Regulatory Services
9:40 a.m.	MEETING GUIDELINES AND AGENDA	**Jay Boggs**, Siemens PTI
9:45 a.m.	IRP PROCESS AND TOOLS	**Peter Berini,** Siemens PTI
10:00 a.m.	INFORMATIONAL RFP'S	**Angelina Martinez,** Siemens PTI
10:15 a.m.	REFERENCE CASE DEVELOPMENT	**Peter Berini,** Siemens PTI, **Thijs Everts,** Siemens PTI
10:45 a.m.	BREAK	
11:00 a.m.	RESOURCE OPTIONS – SUPPLY SIDE	**Thijs Everts**, Siemens PTI
11:30 a.m.	LUNCH	
12:30 p.m.	RESOURCE OPTIONS – DSM	**Thijs Everts**, Siemens PTI, **Chad Burnett**, AEP Load Forecasting, **Jeffrey Huber**, GDS Associates
1:15 p.m.	SCENARIOS	**Peter Berini,** Siemens PTI
1:30 p.m.	STAKEHOLDER INTERACTION	**Art Holland**, Siemens PTI, **Jay Boggs**, Siemens PTI
2:00 p.m.	ADJOURN	

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I&M 2021 IRP PROCESS AND TOOLS

Definitions

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Term	Definition
AURORAxmp	Electric modeling forecasting and analysis software. Used for capacity expansion, chronological dispatch, and stochastic functions
Condition	A unique combination of a Scenario and a Sensitivity that is used to inform Candidate Portfolio development
Deterministic Modeling	Simulated dispatch of a portfolio in a pre-determined future
Renewable Portfolio Standards	Renewable Portfolio Standards (RPS) are policies designed to increase the use of renewable energy sources for electricity generation
Portfolio	A group of resources to meet customer load
Preferred Portfolio	The portfolio that management determines will perform the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for several randomly generated potential future states
Reference Scenario	The most expected future scenario that is designed to include a current consensus view of key drivers in power and fuel markets (reference case, consensus case)
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
Sensitivity Analysis	Analysis to determine the impact of early retirements and other inputs portfolios are most sensitive to

Integrated Resource Plan Overview

The purpose of the IRP is to provide a roadmap at a point in time that AEP I&M can use as a planning tool when evaluating resource decisions necessary to meet forecasted electric energy demand. The approach is meant to balance affordability, reliability, and sustainability for customers and stakeholders in the development and selection of the **Preferred Portfolio**.

Development of Reference and Candidate Portfolio

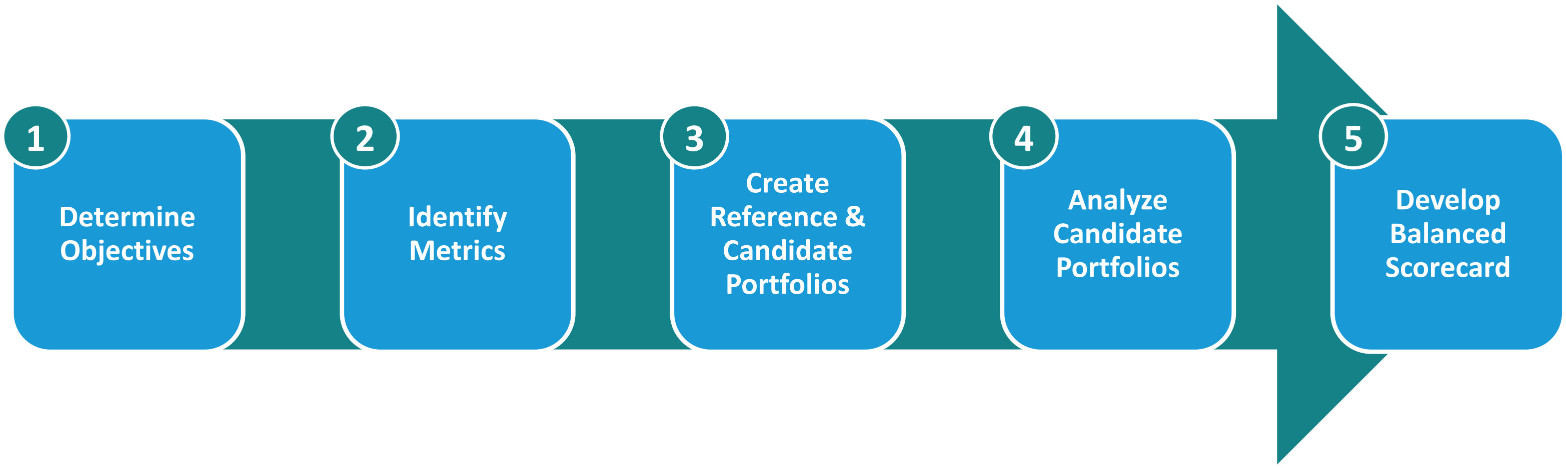
- The end goal of the IRP is to develop a **Preferred Portfolio** (set of supply- and demand-side resources) that can be used as a planning tool to inform future resource actions for electric energy demand to serve load
- I&M has partnered with Siemens PTI to create a **Reference Portfolio** and a set of **Candidate Portfolios** based on a series of inputs that are informed by various **Scenarios** and **Sensitivities**
- The **Reference Portfolio** and the **Candidate Portfolios** will be tested, analyzed and used by I&M management to identify the **Preferred Portfolio**

The discussions today will be focused on the approach and progress for developing the **Reference Portfolio**.

IRP 5-Step Process

Siemens PTI applies the following 5-Step process for modeling, analyzing, and reporting the **Reference Portfolio** and **Candidate Portfolios** related to the AEP I&M IRP. The process, detailed below, provides a holistic approach to identifying the **Preferred Portfolio** that best meets I&M's defined **Objectives** and **Metrics** over a wide range of potential future conditions.

Siemens PTI: Approach to Integrated Resource Plan Modeling



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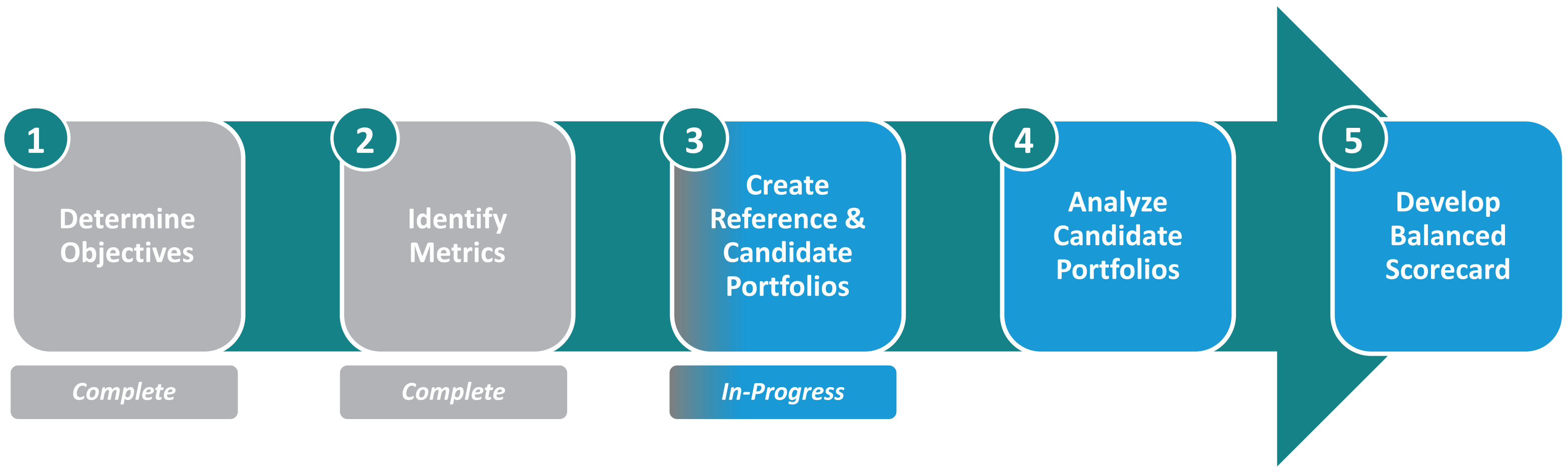

Step 1: Determine Objectives

The purpose of the IRP is to evaluate I&M's current energy resource portfolio and a range of alternative future portfolios to meet customers' electrical energy needs in an affordable and holistic manner. The process evaluates **Candidate Portfolios** in terms of environmental stewardship, market and price risk, reliability, and resource diversity.

IRP Objectives
Affordability
Rate Stability
Sustainability Impact
Market Risk Minimization
Reliability
Resource Diversity

Each **Objective** is important and worthy of balanced consideration in the IRP process

Step 2: Assign Metrics

For each **Candidate Portfolio**, the **Objectives** are tracked and measured through **Metrics** which evaluate portfolio performance across a wide range of possible future market conditions. All measures of portfolio performance are based on probabilistic modeling of 200 futures and addressed in Step 4: Analyze Candidate Portfolios.

IRP Objectives	IRP Metric	Unit
Affordability	NPV-RR	$
Rate Stability	95^{th} percentile value of NPV-RR	$
Sustainability Impact	CO_2 Emissions	tons
Market Risk Minimization	Spot Energy Market Exposure (Purchases/Sales)	%
Reliability	Reserve Margin Exposure	%
Resource Diversity	Mix of Baseload Resources	MW

Objectives will be tracked through identified **Metrics** that will be used to measure and evaluate performance of the Candidate Portfolios

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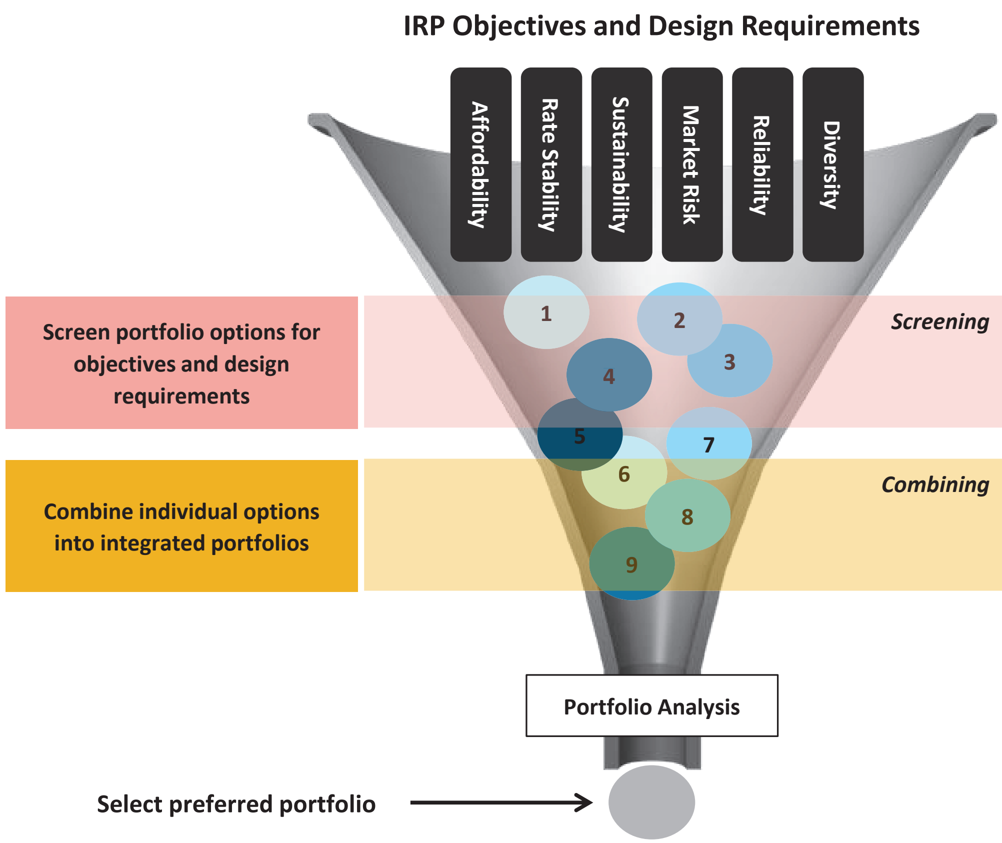
Step 3A: Create Reference and Candidate Portfolios

I&M and Siemens have developed **a Reference Case**, two alternative **Scenarios**, and a handful of **Sensitivities** to implement a scenario- and sensitivity-based approach to inform **Candidate Portfolios**. Each **Candidate Portfolio** will be developed from the **Scenarios** and/or the **Sensitivities** below.

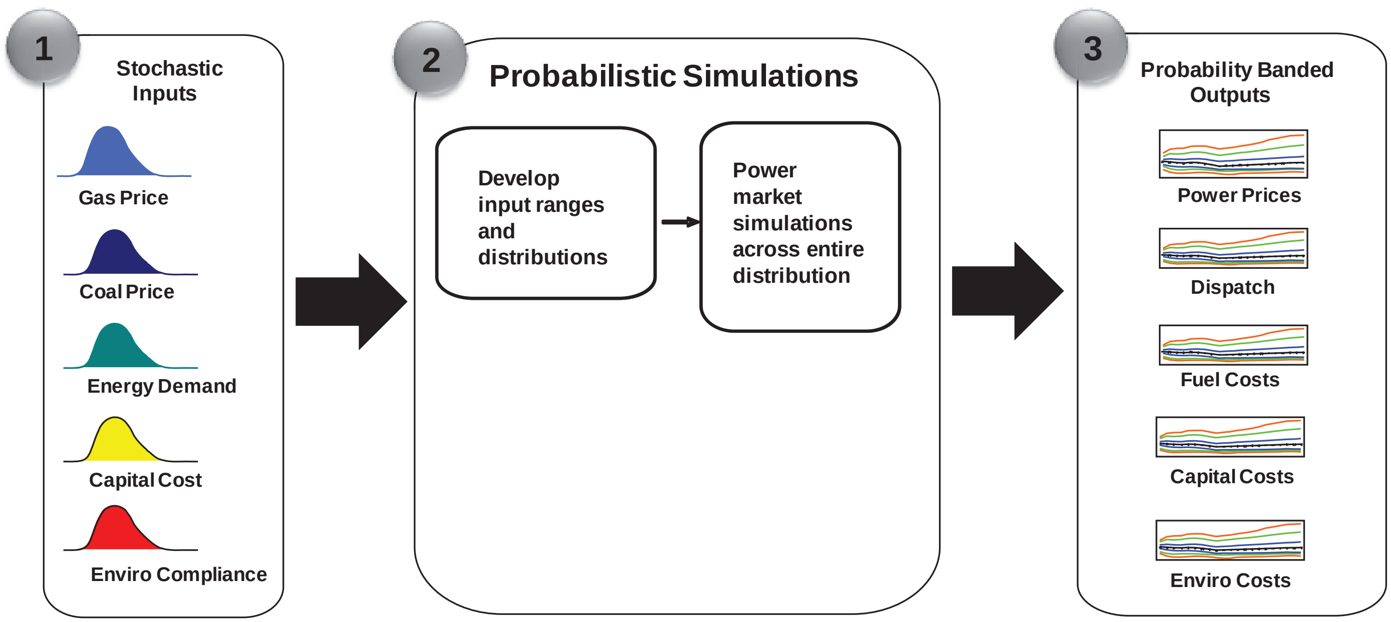
#	Group	Portfolio	Notes
1	Reference	Reference Case	Rockport (2028) and Cook (2034, 2037) Retire as Planned
2	R-A Sensitivity	Reference with Rockport Sensitivity	Rockport Unit 1 Early Retirement (2025)
3	R-B Sensitivity	Reference with Rockport Sensitivity	Rockport Unit 2 Early Retirement (2026)
4	R-C Sensitivity	Reference with Rockport Sensitivity	R-A Sensitivity : 50% of Rockport 2 Capacity
5	R-D Sensitivity	Reference with Rockport Sensitivity	R-B Sensitivity : 50% of Rockport 2 Capacity
6	C-A Sensitivity	Reference with Cook Sensitivity	Cook Unit 1 and Unit 2 License Extensions
7	Scenario	Rapid Technology Advancement	Low Renewable, Storage and EE/DR Costs
8	Scenario	Enhanced Regulation	High Commodity Prices, such as Gas, Coal and CO2

Step 3B: Screen Candidate Portfolios



Step 4: Analyze Candidate Portfolios

Candidate Portfolios are then subjected to **Probabilistic Simulations** (stochastic risk analysis) to measure performance across many future scenarios. The stochastic process will produce hundreds of internally consistent simulations that can provide a more realistic understanding of the potential variation in future scenarios.



Step 5: Develop Balanced Scorecard

Detailed portfolio results will be included for each **Candidate Portfolio** in the report write-up filed with the Commission. The **Candidate Portfolios** will be summarized in terms of each **Objective** and **Metric** through a balanced scorecard.

Balanced Scorecard (Illustrative)

	Affordability	Rate Stability	Sustainability Impact	Market Risk Minimization	Reliability	Resource Diversity
Candidate Portfolios	NPV RR	95th Percentile Value of NPV RR	CO2 Emissions	Purchases as % of Generation	Reserve Margin	Mix of Resources
Reference Case	$92.0	$115.0	-62.0%	10.0%	15%	5
Portfolio #1	$94.0	$138.0	-39.0%	15.0%	15%	4
Portfolio #2	$108.0	$145.0	-50.0%	18.0%	15%	6
Portfolio #3	$81.0	$123.0	-38.0%	24.0%	15%	4
Portfolio #4	$97.0	$146.0	-42.0%	42.0%	15%	4
Portfolio #5	$101.0	$167.0	-54.0%	34.0%	15%	5
Portfolio #6	$87.0	$113.0	-64.0%	41.0%	15%	3
Portfolio #8	$102.0	$172.0	-40.0%	34.0%	15%	5
Portfolio #9	$120.0	$198.0	-90.0%	24.0%	15%	6
Portfolio #10	$99.0	$210.0	-84.0%	12.0%	15%	5

FEEDBACK AND DISCUSSION

INFORMATIONAL RFP'S

All-Source Informational RFP Process

Issue All-Source Informational RFP

- March 26, 2021: Draft RFP available to Stakeholders
- April 9, 2021: Stakeholder review meeting
- April 23, 2021: Issue RFP

Collect and Analyze Responses

- May 21, 2021: collect Responses
- Siemens' evaluation incl. Q/A with respondents
- Receive I&M 2020 Renewables RFP
- RFP results review with I&M

Evaluate how will the information will Inform the IRP

- Create price curves for all technologies based on Siemens internal forecasts
- Discuss feedback on the use of All-Source data and confirm approach

Provide resource options to Siemens IRP Modeling team

- Provide resource options to Siemens IRP Modeling team

Responses Visualization

- All responses for the All-Source Informational RFP are for projects located in Indiana or Michigan, interconnected to PJM with a COD between 2024-2025
- The pricing range between the 2021 All-Source Informational RFP and the I&M 2020 Renewables RFP are similar.
- Both RFPs responses were utilized as a key input for I&M's 2021 IRP process.
- Total data points analyzed 66.

Project Type	2021 All-Source Informational RFP	2020 Renewables RFP
Solar PPA	10	13
Solar BOT	8	10
Solar + Storage PPA	4	4
Solar + Storage BOT	3	7
Wind PPA	1	2
Wind BOT	-	2
CCGT/CT Capacity PPA	1	-
CT Energy PPA	1	-
Stand-alone Storage PPA	2	-
Demand Response	1	-
Not compliant	4	-
Total Data Points Analyzed (excluding not compliant)	**31**	**35**

All-Source Informational RFP Results

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RFP Responses Summary

Plant Parameters

Plant Parameters	Renewables									Dispatchable				Demand Response
Technology	Medium Solar 20-yr PPA	Medium Solar 30-yr PPA	Large Solar 20-yr PPA	Large Solar 30-yr PPA	Solar + Storage	Wind	Solar	Solar + Storage	Wind	CCGT/ CT Capacity	CT Energy	Stand-alone Storage 2-hr	Stand-alone Storage 4-hr	Demand Response
Commercial Structure	PPA	PPA	PPA	PPA	PPA	PPA	BOT	BOT	BOT	PPA	PPA	PPA	PPA	PPA
Capacity Range (MW)	50-200	60	300-600	245-350	10-100	200-300	100-350	100/ 20-50	200	100-200	236	200	200	5 MW first year (+3MW/yr)
Storage Hours (hrs)	NA	NA	NA	NA	4 hr	NA	NA	4 hr	NA	NA	NA	2-hr	4-hr	NA
Capacity Factor Average (%)	24%	24%	24%	24%	24%	38%	24%	24%	38%	NA	NA	NA	NA	NA
Capacity Factor Min-Max (%)	23%-25%	21%-25%	24%-24%	24%-25%	23%-25%	34%-43%	21%-25%	24%-25%	34%-43%	NA	NA	NA	NA	NA
COD Range	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	2024-2025	Operational	Operational	2023	2023	2022
PPA Term	15-25	30	15-25	30	15-30	12	NA	NA	NA	10	10	15	15	20

All-in Capex/ PPA Price, Nominal$/kW	Medium Solar 20-yr PPA	Medium Solar 30-yr PPA	Large Solar 20-yr PPA	Large Solar 30-yr PPA	Solar + Storage PPA ($/kW-m)	Wind PPA	Solar BOT	Solar + Storage BOT	Wind BOT	CCGT/CT Capacity ($/kW-m)	CT Energy ($/kW-m)	Stand-alone Storage 2-hr	Stand-alone Storage 4-hr	Demand Response (Real 2021$/kW-m)
Min	43	43	33	45	6.5	48	1,245	1,674						
Average	48	43	37	46	7.3	48	1,475	1,914		3.95	1.75	5.98	8.96	3.53
Max	54	43	41	47	8.5	48	1,600	2,310						
Data Points	5	1	2	2	4	1	8	3	0	1	1	1	1	1

Renewable RFP Results

Renewable RFP Responses Summary

Plant Parameters

Plant Parameters	Renewables						
Technology	Medium Solar	Large Solar	Solar + Storage	Wind	Solar	Solar + Storage	Wind
Commercial Structure	PPA	PPA	PPA	PPA	BOT	BOT	BOT
Capacity Range (MW)	85-163	200-353	120-183/ 24-32	200	100-353	100-163/ 20-32	200
Storage Hours (hrs)	NA	NA	4 hr	NA	NA	4 hr	NA
COD Range	2023	2023	2023	2023	2023	2023	2023
PPA Term	30	30	15-30	12-30	NA	NA	NA

All-in Capex/ PPA Price, Nominal$/kW	Medium Solar 30-yr PPA	Large Solar 30-yr PPA	Solar + Storage PPA ($/kW-m)	Wind PPA	Solar BOT	Solar + Storage BOT	Wind BOT
Min	43	41	8.6	45	1,431	1,666	1,953
Average	50	44	8.7	45	1,525	1,781	2,060
Max	59	50	9.0	46	1,592	1,842	2,168
Data Points	10	3	4	2	10	7	2

FEEDBACK AND DISCUSSION

I&M 2021 IRP REFERENCE CASE

Reference Scenario Inputs

I&M and Siemens PTI developed a set of base case assumptions. In Stakeholder Workshop #1, the team presented illustrative inputs. The inputs included herein are meant to represent the planned reference case inputs being used to construct the Reference Case, including the following key drivers:

Key Market Drivers:

- I&M and PJM energy and demand
- Henry Hub natural gas prices
- PRB Coal Prices
- Capital Costs for various generation technologies

Fundamentals Forecast

- Base Case: Reflects EIA Reference scenario
- Base Carbon Case: Includes a $15/metric ton carbon price beginning in 2028, escalating at 3.5% annually thereafter

AURORAxmp and other model and tools

AURORAxmp (AURORA) is an industry standard model for electricity production costing, resource valuations, market risk analysis and market simulations.

- AURORA is licensed by hundreds of clients in North America, ranging from consultants to utilities to regulatory bodies
- AURORA is accepted in many regulatory jurisdictions
- AEP I&M and Siemens PTI will use the AURORA model in the IRP to provide the following analysis:
  - Commodity forecasts and base case assumption development
  - Least cost optimization of different portfolios
  - Simulation of the performance of different portfolios under a variety of market conditions
  - Production cost modeling to provide market prices for energy
  - Emissions tracking based on unit dispatch
  - An analysis of various regulatory structures such as reserve margins, RPS requirements, others
  - Risk analysis based on stochastic simulation of key inputs

Reference Case: Fuel Prices

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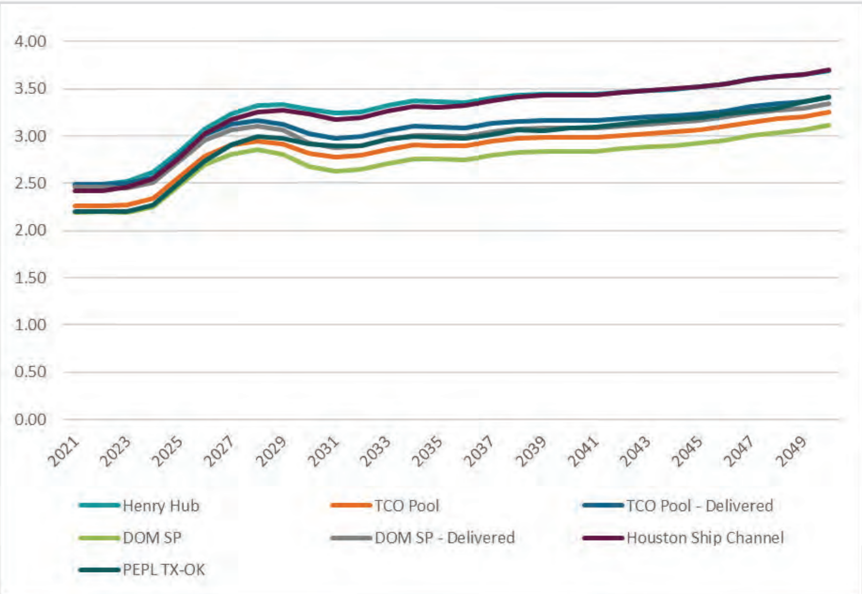
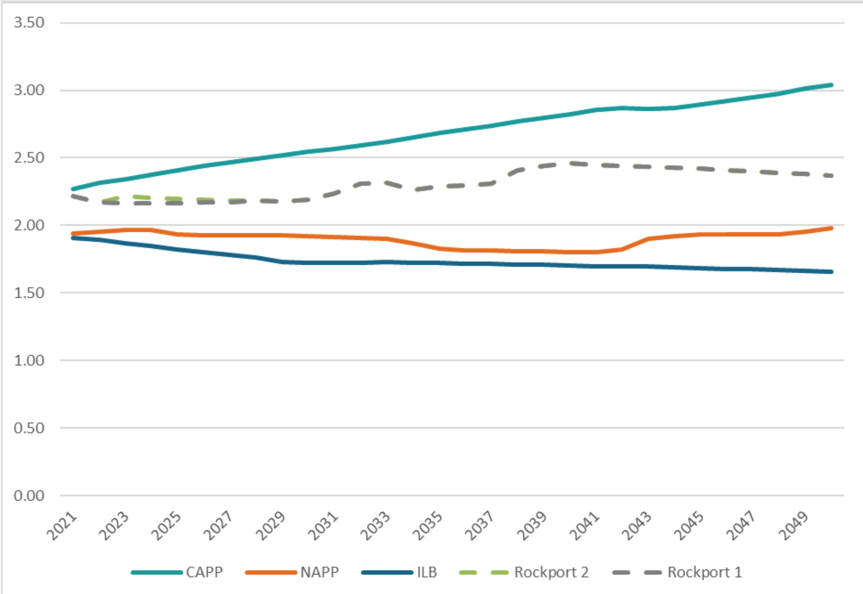
Natural Gas Forecast (2019$/MMBtu)

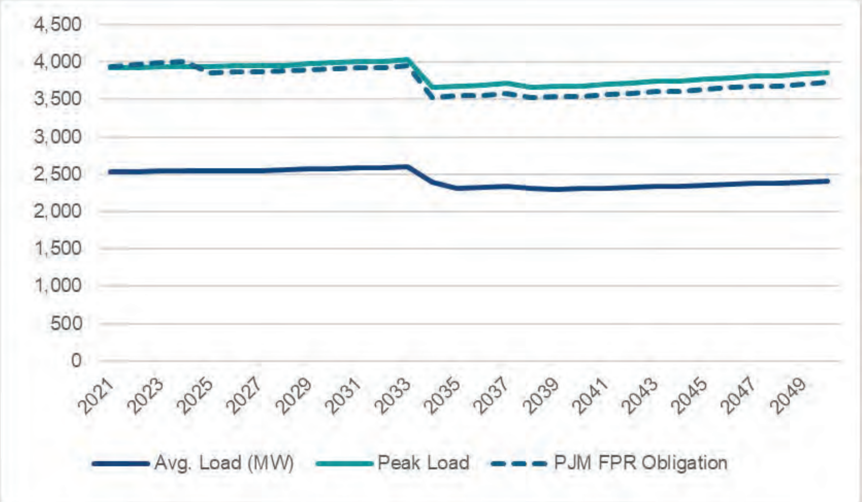


Coal Basin Price Forecast (2019$/MMBtu)

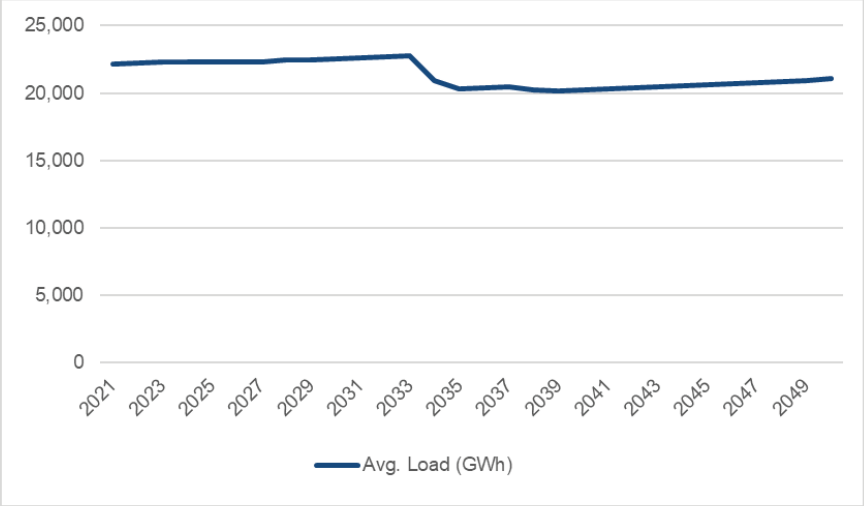


Reference Case: Load Forecast

I&M Load (MW)



I&M Energy (GWh)



Reference Case: Emissions Price Forecast

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Exhibit AG-14
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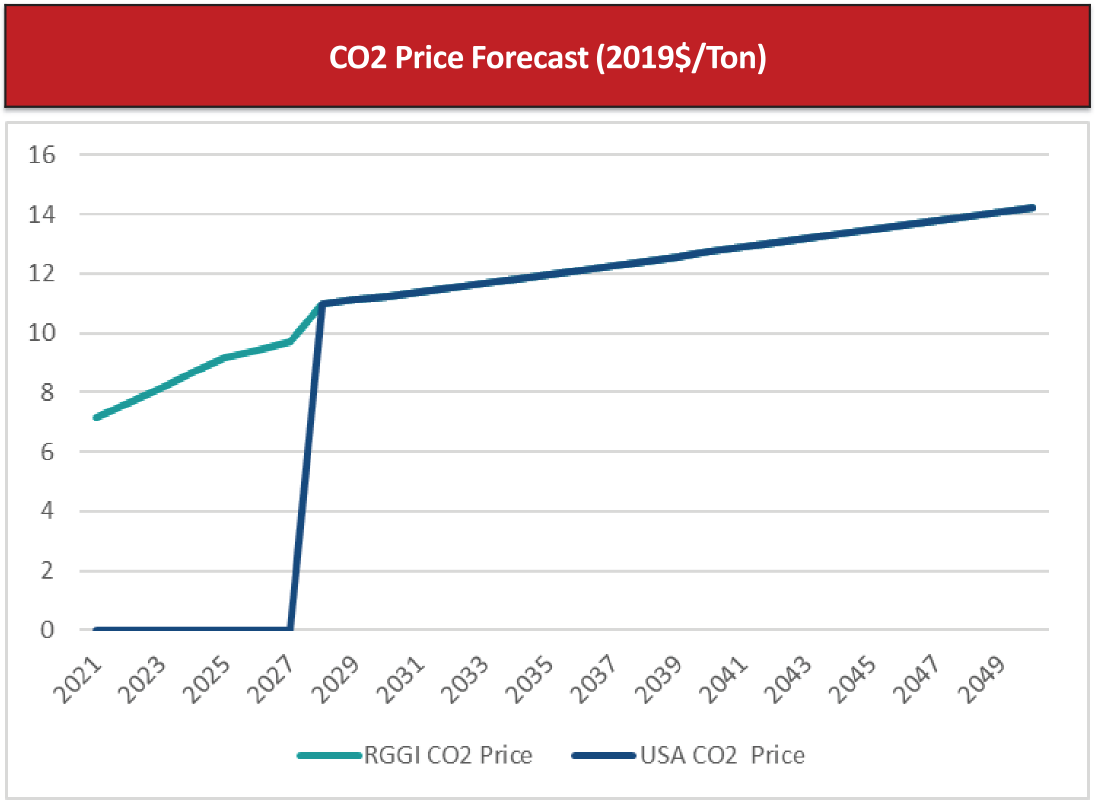
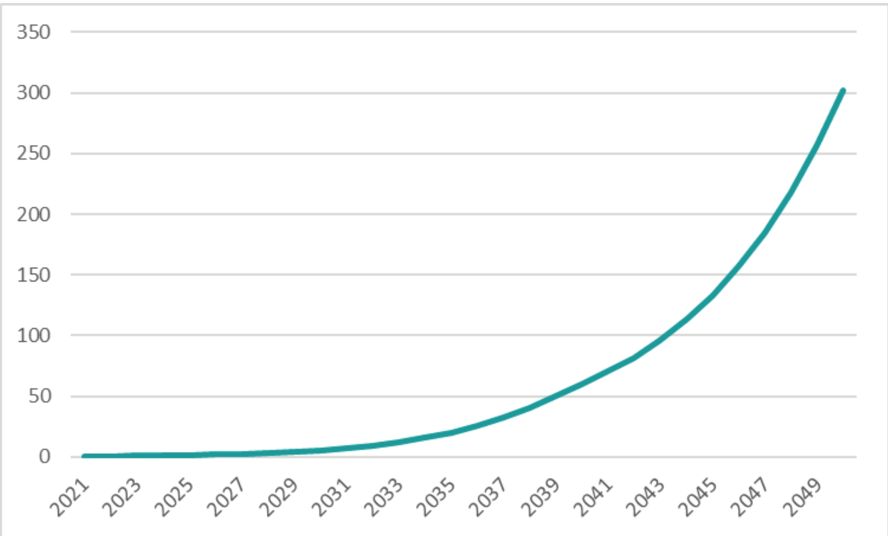
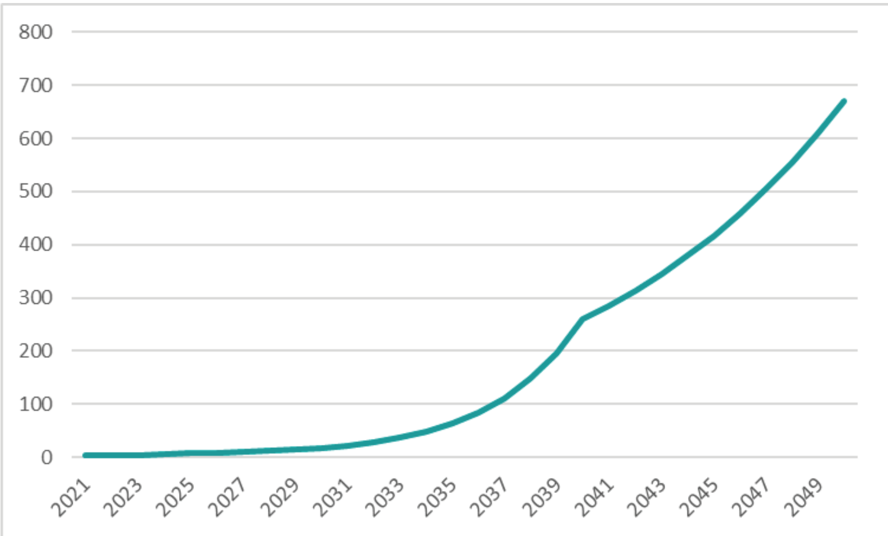


Reference Case: Solar & EV

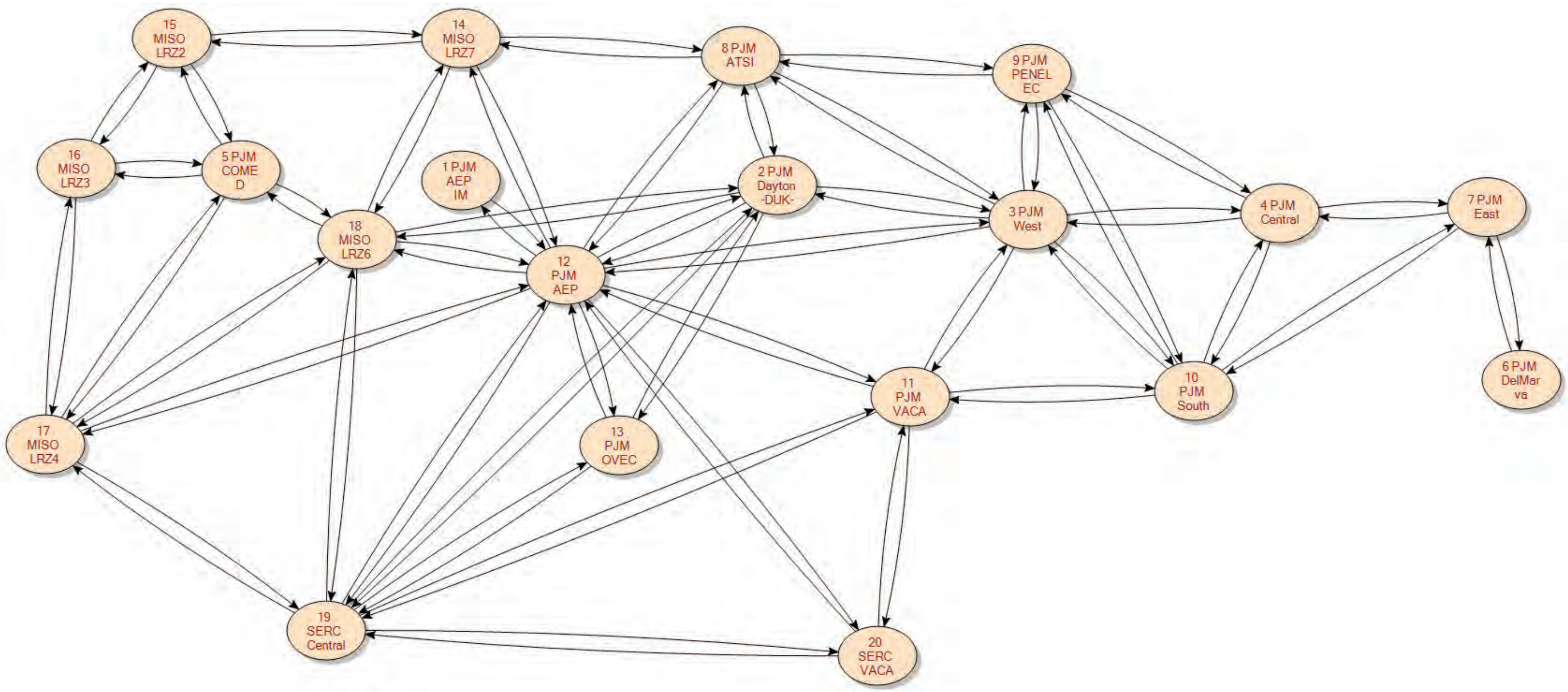
I&M DG Solar Capacity (MW)



I&M Electric Vehicle Demand (MW)



Reference Case: Transmission Topology



FEEDBACK AND DISCUSSION

RESOURCE OPTIONS – SUPPLY SIDE

ADDITIONAL SLIDES PENDING

Resource Overview – Self-Build Baseload and Peaking Options

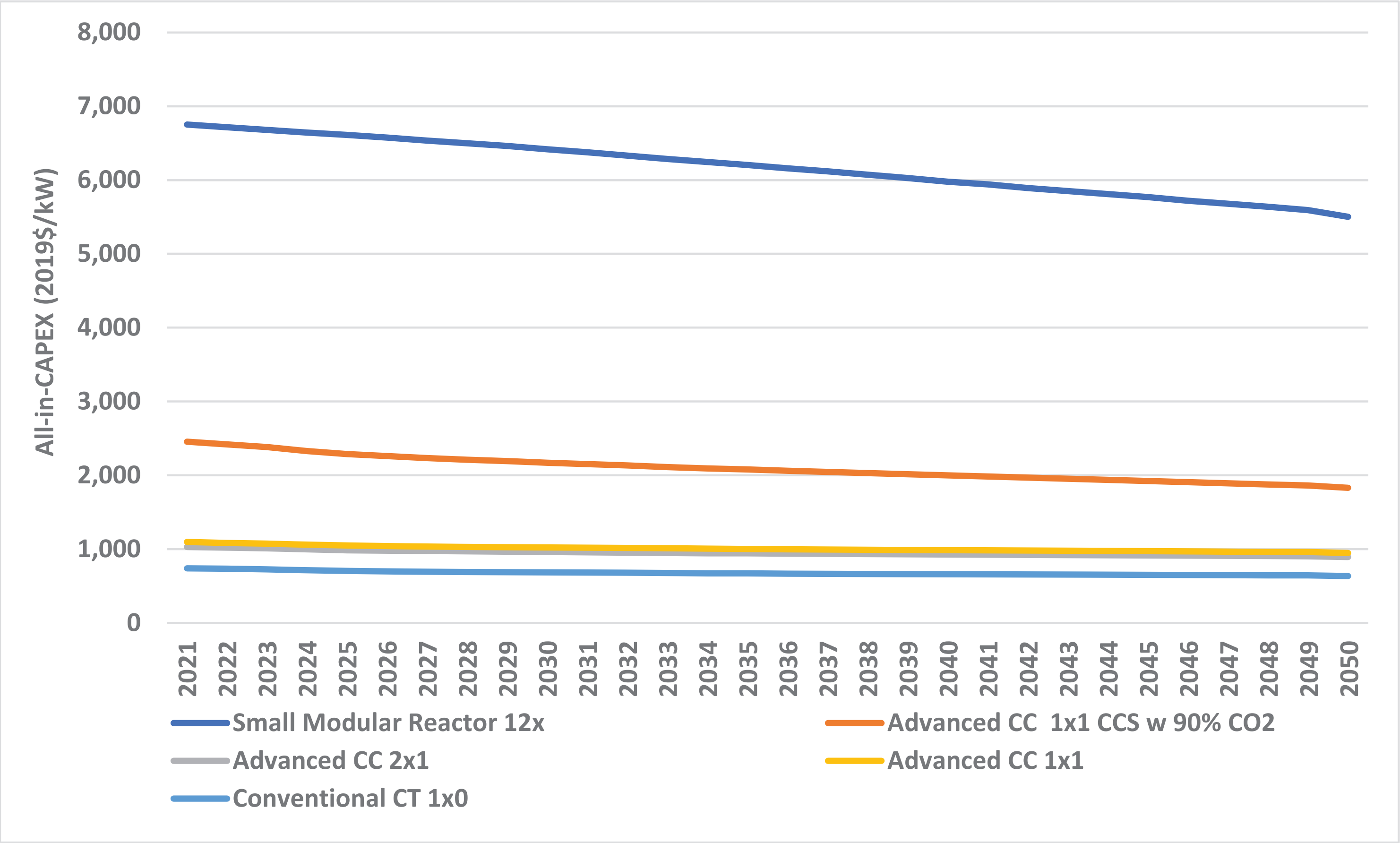
Sources: EIA, Siemens

Technology	Small Modular Reactor	Advanced CC	Advanced CC	Advanced CC	Conventional CT
	12x	1x1 CCS w 90% CO2	2x1	1x1	1x0
Fuel	Uranium	Nat. Gas.	Nat. Gas.	Nat. Gas.	Nat. Gas.
Construction Time (Yrs)	10	7	6	5	5
Book Life (Yrs)	40	40	30	30	30
Size (MW)	600	380	1030 *	420	230
Average Heat Rate (Btu/kWh), HHV	10,046	6,431	6,370	6,431	9,905
VOM (2019$/MWh)	3.03	5.84	1.87	2.55	0.60
FOM (2019$/kW-yr)	96.14	27.58	11.26	14.10	6.99

* The Optimization routine can select the Gas CC 2x1 Configuration in smaller increments

Resource Overview – Self-Build Baseload and Peaking Options

Sources: EIA, Siemens



Feedback and Discussion

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RESOURCE OPTIONS – DSM/EWR

Demand Side Management Resource Options

Siemens PTI, GDS and the I&M IRP team collaborated on the development of the forecasted inputs needed to include Demand Side Management (DSM) Resources in the analysis.

The AEP I&M IRP included the following DSM options:

- Energy Efficiency (EE)
- Demand Response (DR)
- Distributed Energy Resources (DER)

Resource Overview

DSM resources act as a load reducing resource and decrease the need for capacity and/or generation from new resource options

- **Energy Efficiency** has become an increasingly important measure in Integrated Resource Planning since it reduces the generation needs and can be an effective tool in carbon reduction strategies.

- **Demand Response** provides a reduction in Peak Capacity needs which can act as a carbon reduction strategy decreasing the operating time of less efficient Peaking resources.

- **Distributed Energy Resources** are drastically increasing in the US as renewable energy, specifically solar, has significantly decreased in costs due to policy incentives and learning curves. This allows homeowners or commercial and industrial entities to generate their own energy, decreasing the need for energy generation from utilities.

DSM Resource Treatment

Measure	Program	Treatment	# of Programs
Energy Efficiency	CVR	Going-In	4
	Low Income Qualified (IQW)	Going-In	3
	Long-Term Vintages	Optimized	39
Demand Response	Residential	Non-Optimized	1
	Commercial & Industrial	Non-Optimized	1
Distributed Energy Generation	Rooftop Solar (DG)	Going-In	2
	Combined Heat & Power (CHP)	Going-In	1

Optimized: These programs will be exposed to the optimization routine, and the capacity and generation impact will be determined by the economic need for these programs.

Non-Optimized: The capacity included in the analysis; however, the actual impact to each Portfolio may depend on the economic dispatch of the program.

EE Bundle Development For IRP

GDS produced value-based bundles based on statistical cluster technique

- k-means clustering is a way to group data points together based on some user defined metric(s)
- Data is grouped together by minimizing the Euclidean distance between data points and a randomly selected centroid (single point) within the data
  - Of course, but what does that mean??
- Essentially, data points that are the most similar are grouped together within a cluster
  - The number of clusters affects the groupings
  - Iterative process to get the closest/most similar group of data points in each cluster

EE Measures clustering

- **Residential and Non-Residential measures were kept separate**
  - Cluster process was developed separately for each
- **NPV $ Benefits (and costs)/lifetime kWh were used as the metrics to determine clusters**
  - Both metrics were used to determine cluster groupings
- **Clustering process was analyzed using 2 through 20 clusters**
  - There is no "correct" answer, rather a range of clusters that provide the best results based on the various metrics the analysis provides

EE Measures clustering

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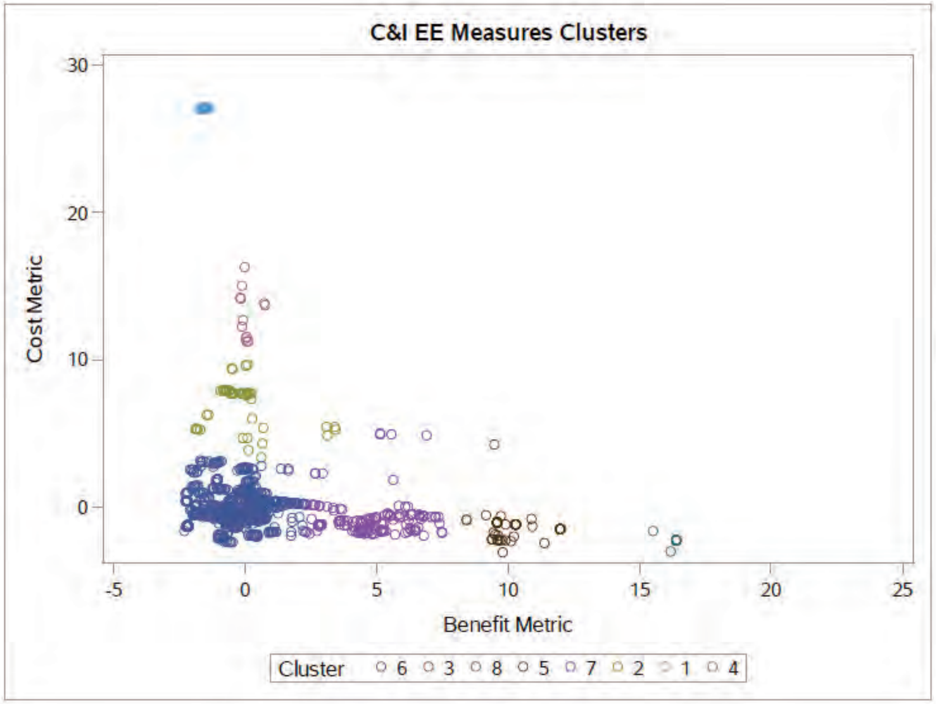
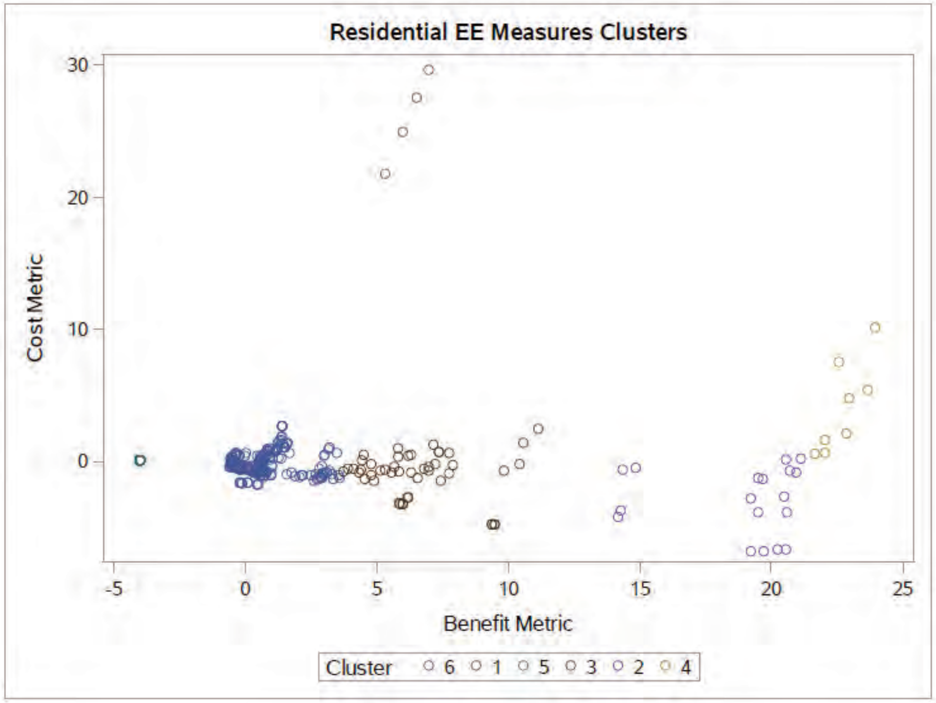




EE Measure BUNDLES

- Measure cluster assignment was used to create bundles
- EE bundles are based on the *gross* Realistic Program Potential Determined from the IRP
- Bundles are *not* equal in total savings
- Costs were adjusted to reflect the T&D benefits of each bundle
- Each bundle has unique 8,760 hourly shape

Residential

Five bundles

1 bundle represents ~ 85% of savings

Income-Qualified

Single bundle (non-optimized)

Savings modified from MPS to align with historical spending

C&I

8 bundles

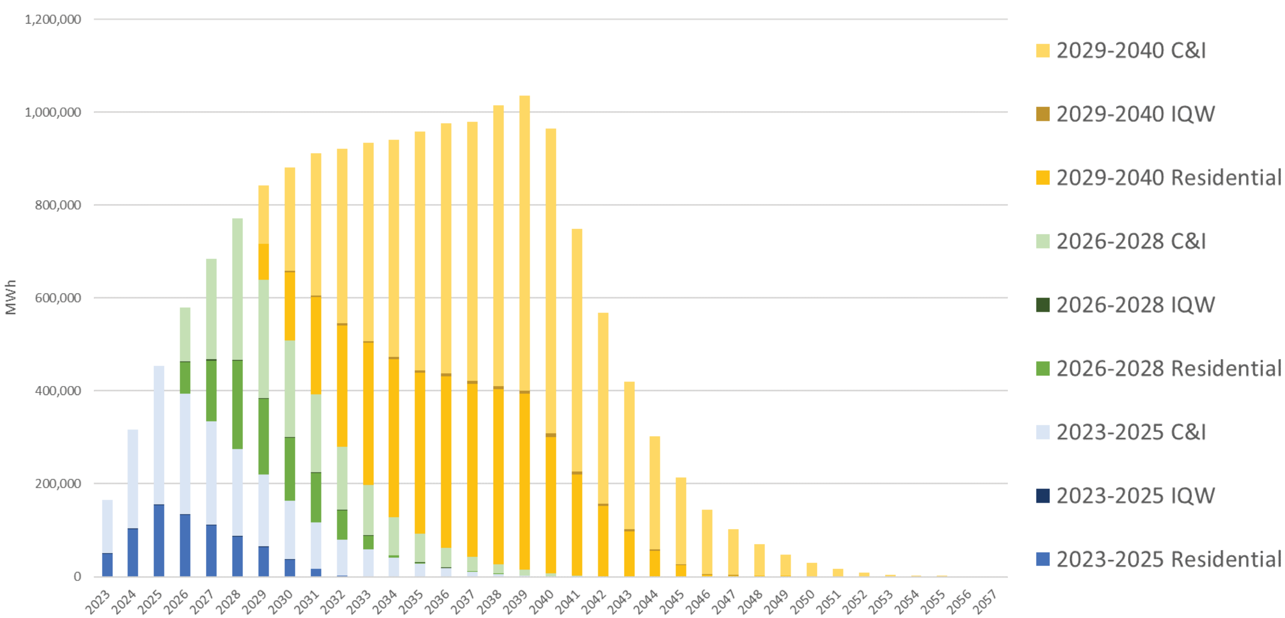
1 bundle ~ 55% of savings

2 additional bundles ~ 30% of savings

EE Measure BUNDLES

Annual costs and savings (inclusive of line losses) are incorporated

Shown below are sector level impacts only ***(actual sectors had additional bundles as indicated on the prior slide)***



Levelized Cost ($/MWh)

Range	Mean	
$13-$155	$34	Vintage #3
$298	$298	
$36-$798	$43	
$12-$154	$29	Vintage #2
$267	$267	
$35-$793	$42	
$10-$155	$24	Vintage #1
$258	$258	
$36-$792	$42	

Exhibit AG-14
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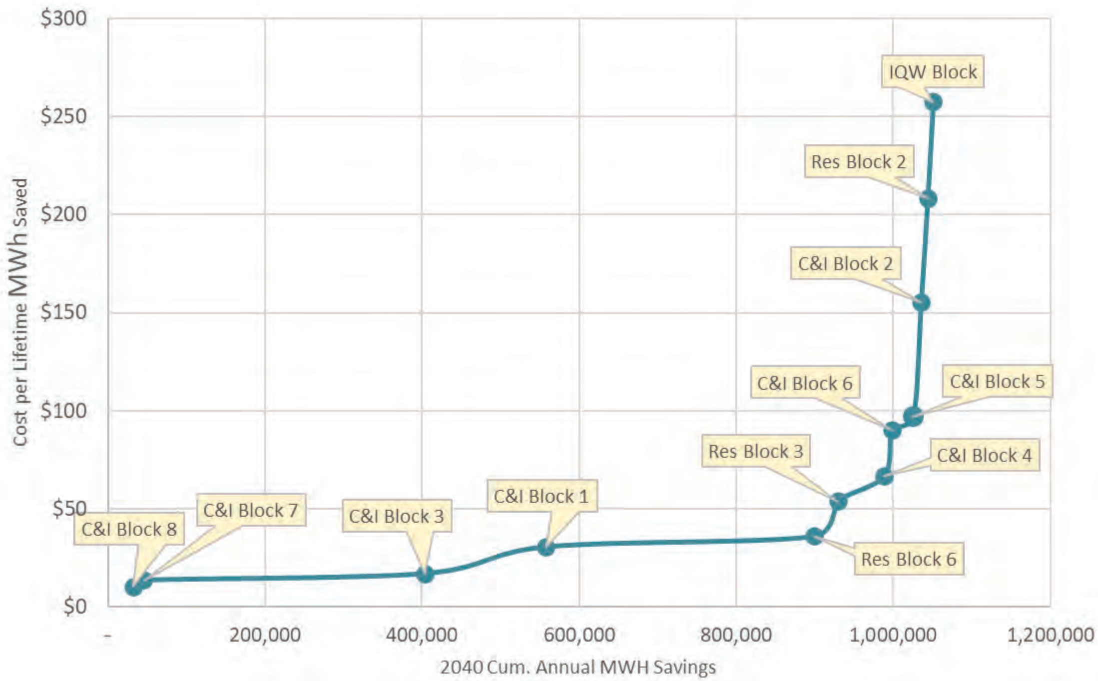
EE Measure Bundles

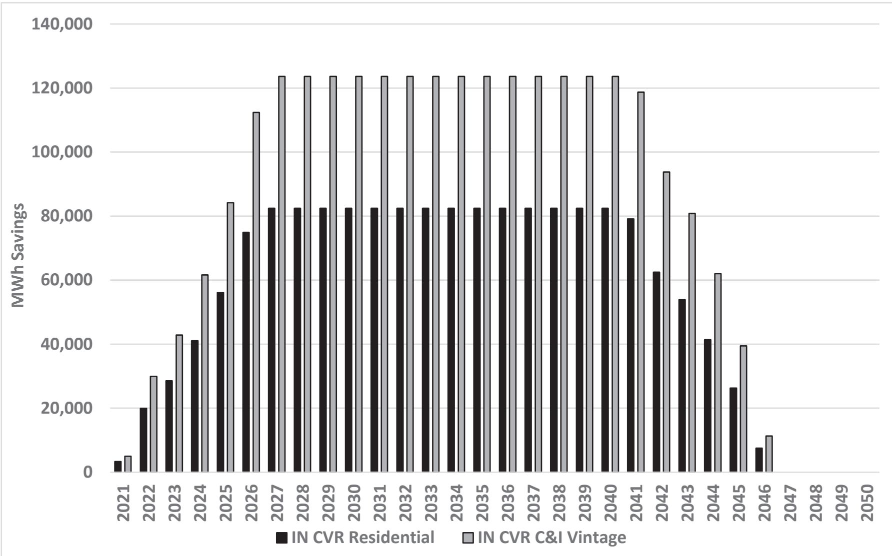
- Supply Curve demonstrates the breakout of the individual DSM bundles and their relative contribution to the cumulative annual impacts in 2040.
- The largest C&I block is 3rd on the supply curve (~$18/lifetime MWh).
- The largest residential block is 5th on the supply curve (~$36/MWh)

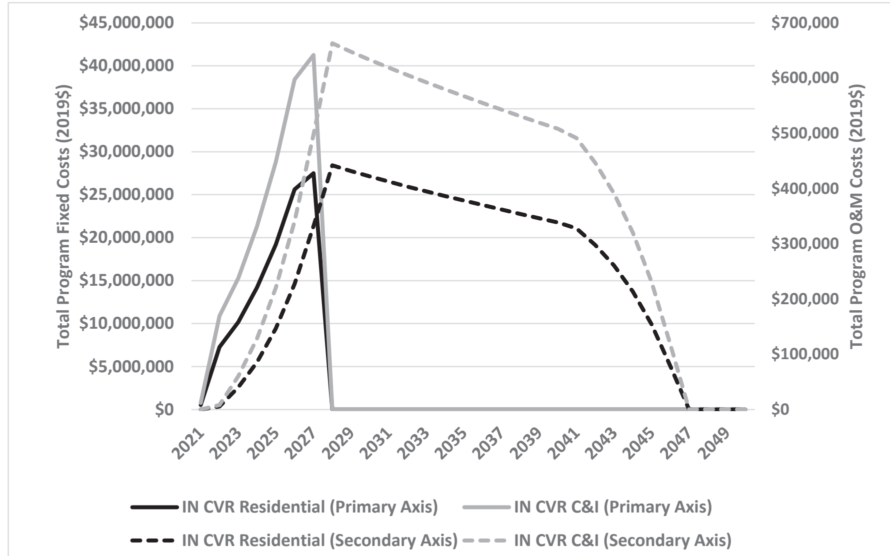


** Two additional residential blocks, with a cost per lifetime MWh saved $300 were omitted from the supply chart. They represent less than 0.1% of the 2040 Cumulative Annual MWh savings in 2040.*

Siemens Parametrization of EE "Going-in" Data
Indiana CVR

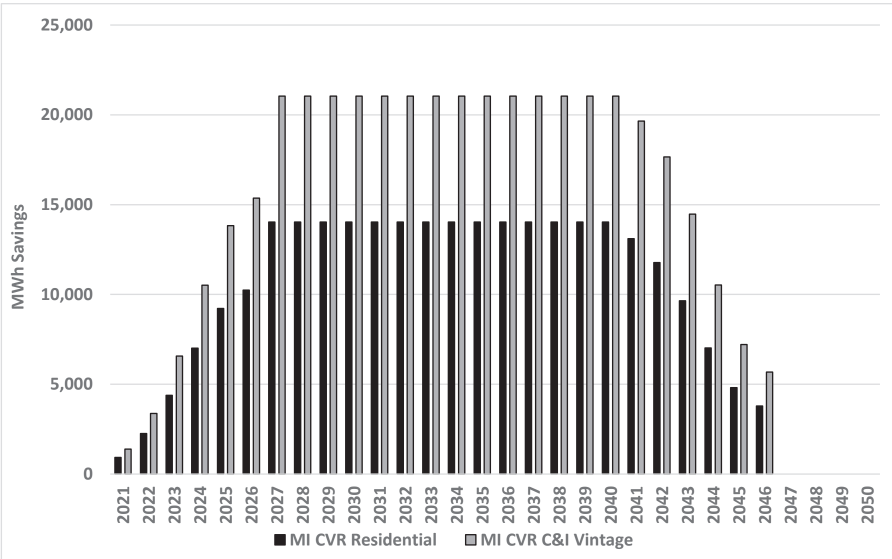
Exhibit AG-14
Case No. U-20530
August 24, 2021
Page 50 of 73

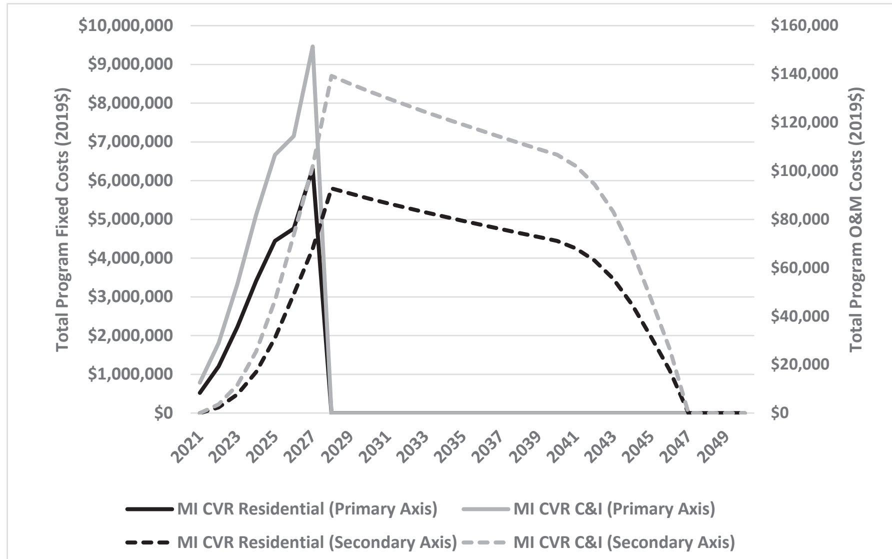




Siemens Parametrization of EE "Going-in" Data
Michigan CVR

INDIANA MICHIGAN POWER
An AEP Company





Reference Case: Realistic Achievable Potential Demand Response Data

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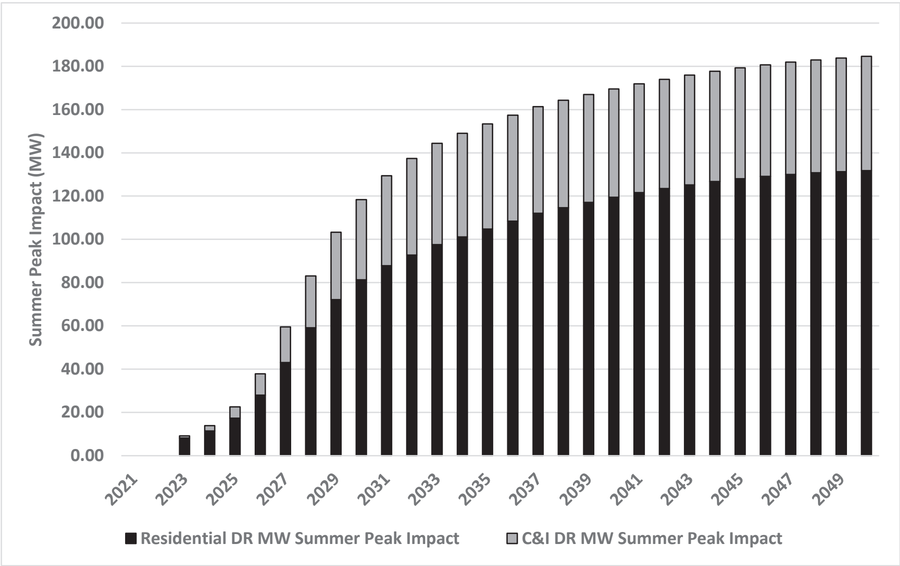

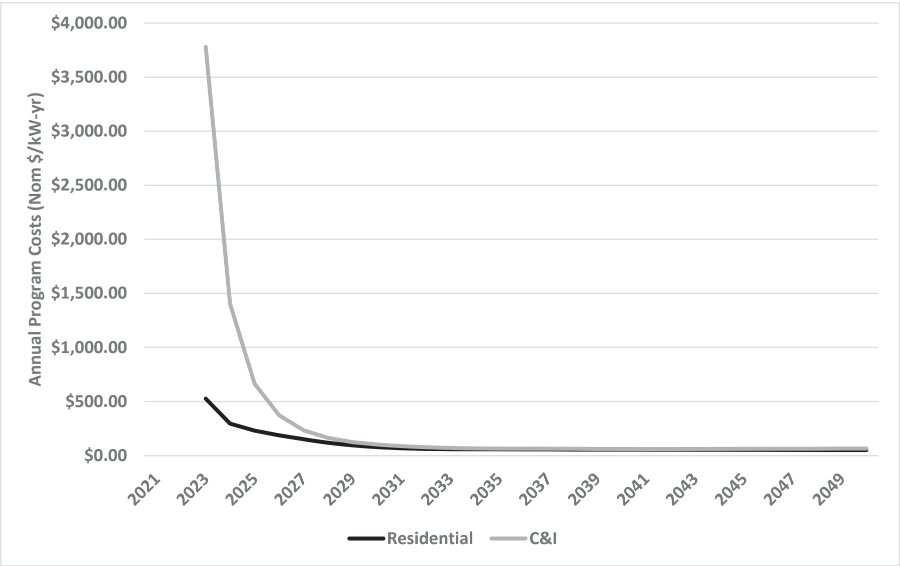

Peer Utility Review

In response to Stakeholder comments after the 2nd Stakeholder meeting, I&M reached out to multiple Investor-Owned Utility (IOU) in the states of Indiana and Michigan to see how they were accounting for energy efficiency in their IRPs and load forecast models.

I&M also reached out to Itron (the developer of the SAE models) to review I&M's approach to modeling energy efficiency in the SAE load forecast models.

Utilities Surveyed

Indiana Utilities	Michigan Utilities
AES (IP&L)	Consumers Energy
Centerpoint (Vectren)	DTE Electric
Duke Energy	
NIPSCO	

Benchmark to Other Utilities in IN & MI

	I&M	Utility A	Utility B	Utility C	Utility D	Utility E	Utility F
Itron SAE Models?	Yes	Yes	Yes (use Itron)	No (traditional econometric model)	No (Use External Consultant)	Yes	Yes
DSM Optimized?	Optimized	Target	Optimized	Target	Optimized	Optimized	Target
DSM Model Approach	Supplemental Efficiency Adjustment Matrix based on measure life	Regress DSM as independent variable	Regress DSM as independent variable	Model programs base on measure life. Assume no savings after measure life expires	Use Add-back method with Aurora	Regress DSM as independent variable	Use Add-back method with MPS EE targets
Adjusting DSM savings in Load Forecast?	Supplemental Efficiency Adjustment used in conjunction with SAE model to prevent double counting EE	DSM coefficient used to discount future DSM savings in forecast	DSM coefficient used to discount future DSM savings in forecast	Load forecast is standard econometric model that doesn't attempt to account for future EE. As a result, no adjustment needed for future DSM savings.	Load forecast is standard econometric model that doesn't attempt to account for future EE. As a result, no adjustment needed for future DSM savings.	DSM coefficient used to discount future DSM savings in forecast	Add back historical savings, and assume MPS savings for future EE savings.

Benchmarking Observations

- 5 out of the 7 IOUs surveyed in IN and MI use Itron's SAE model.
- Utilities that operate exclusively in MI are assuming a target for DSM/EWR whereas most IN and multi-state utilities are optimizing DSM as a supply side resource.
- The majority of IOU's using Itron's SAE model are modeling the DSM series as an independent variable in the regression.
- I&M's Supplemental Efficiency Adjustment (SEA) gets to the same levels as using DSM variable as a independent variable in the regression. In future IRP cycles, I&M will replace the SEA approach by modeling DSM series as an independent variable in the regression equation.
- Many IOU's are using a different load forecast methodologies for their IRP than they use in base rate case, fuel, and/or rider filings. This is not the case for I&M.

SEA vs DSM as an Independent Variable

I&M Indiana

Residential Lighting

5 / 10	900,000	19,899,654	15,515,989	15,306,274	19,651,372	15,067,351	15,169,832	11,939,913	1,070,007	609,626	-	-
	2008	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008	900,000											
2009	688,574											
2010	440,204											
2011	207,749											
2012	49,670											
2013												
2014												
2015		19,899,654										
2016		15,224,867	15,515,989									
2017		9,733,237	13,818,033	15,306,274								
2018		4,593,477	11,871,004	13,631,267	19,651,372							
2019		1,098,246	9,759,036	11,710,554	17,500,870	15,067,351						
2020			7,589,116	9,627,132	15,034,911	13,418,490	15,169,832					
2021			5,485,731	7,486,541	12,360,053	11,527,759	13,509,757	11,939,913				
2022			3,581,587	5,411,585	9,611,798	9,476,858	11,606,165	10,633,296	1,070,007			
2023			2,003,944	3,533,178	6,947,809	7,369,680	9,541,315	9,135,012	952,914	609,626		
2024			856,315	1,976,859	4,536,165	5,327,113	7,419,806	7,509,804	818,643	542,913	-	
2025			195,335	844,741	2,538,043	3,478,027	5,363,346	5,840,001	672,999	466,414	-	-
2026				192,695	1,084,543	1,946,001	3,501,682	4,221,397	523,358	383,434	-	-
2027					247,396	831,555	1,959,237	2,756,114	378,305	298,178	-	-
2028						189,687	837,211	1,542,081	246,992	215,535	-	-
2029							190,977	658,954	138,195	140,721	-	-
2030								150,315	59,053	78,735	-	-
2031						**Total to Subtract from LF**	**69,099,327**		13,471	33,645	-	-
2032						**Total Savings w/ no adjustment**	**151,698,321**			7,675	-	-
						Supplemental Efficiency Adjustment Impact	**46%**				-	-

JURIS	CLASS	DSM Variable Coefficient	T-Stat	P-Value
IM-IN	Residential	-0.51	(2.88)	0.43%
	Commercial	-0.47	(5.70)	0.00001%
I&M-MI	Residential	-0.52	(4.42)	0.0018%
	Commercial	-0.39	(1.88)	6.12%
	Average	**-0.47**		

FEEDBACK AND DISCUSSION

SCENARIOS

Overview of Proposed Scenarios

I&M will use a scenario- and sensitivity-based approach to construct future market and regulatory environments. The Reference scenario is the most expected future scenario and includes the base case inputs provided by AEP I&M. The changes in the alternative scenarios are shown relative to the Reference scenario.

All Portfolios in each proposed scenario will achieve a Net Zero by 2050 Carbon Reduction goal which aligns with the AEP Corporate Goal.

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
Reference	Base	Base	Base	Base	Base	Base
Rapid Technology Advancement	Base	Base	Base	Base	Low	Low
Enhanced Regulation	Base	High	High	High	Base	Base
High Market Price (changed)	High	Varied	Varied	Varied	Base	Base

The directional basis of the Scenario drivers are as compared to the Reference scenario.

Scenario Narrative: Reference Scenario

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
Reference Scenario	Base	Base	Base	Base	Base	Base

The Reference Scenario

The Reference scenario is the most expected future scenario that is designed to include a consensus view of key drivers in power and fuel markets. The existing generation fleet is largely unchanged apart from new units planned with firm certainty or under construction. An increased carbon reduction is assumed to achieve net zero in the electric sector.

In the Reference scenario, major drivers include:

- Coal prices remain relatively flat over the forecast horizon in constant dollars consistent with EIA reference
- Natural gas prices move upward in real dollars to 2050 consistent with EIA reference
- Capital costs are downward sloping for fossil and wind resources, and decline significantly for solar and storage resources
- Carbon regulations limiting CO2 emissions will commence in 2028 and remain in effect throughout the forecast horizon
- Portfolio achieves Net Zero by 2050 without any incremental goals and assuming an $100/ton (nominal) offset is available

Scenario Narrative: Rapid Technology Advancement

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
Rapid Technology Advancement	Base	Base	Base	Base	Low	Low

Rapid Technology Advancement

The Rapid Technology Advancement scenario assumes technological advancements, favorable regulation and overall economies of scale that impact renewable resources. The scenario assumes technology costs for supply- and demand-side renewable resources decline over time, resulting in up to 35% reductions in technology costs; significantly faster than in the Reference scenario.

In the Rapid Technology Advancement scenario, major drivers include:

- Technology cost reductions for renewables and storage result in lower capital costs
- Technological advancement and economies of scale contribute to greater potential for energy efficiency and demand response
- Carbon regulations limiting CO2 emissions will commence in 2028 and remain in effect throughout the forecast horizon
- Thermal generation retirements are driven by unit age-limits and announced retirements, consistent with Reference scenario
- Fundamental drivers (load, commodity prices, net zero requirement by 2050) remain constant to the Reference scenario

Scenario Narrative: Enhanced Regulation

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
Enhanced Regulation	Base	High	High	High	Base	Base

Enhanced Regulation

The Enhanced Regulation scenario assumes increased environmental regulations covering natural gas, coal and CO2. Illustrative examples include a potential fracking ban and increases of carbon reduction targets.

In the Enhanced Regulation scenario, major drivers include:

- Natural gas, coal prices and CO2 prices are increased to reflect enhanced regulation
- Technology costs for thermal and renewable units remain consistent with the Reference scenario
- Thermal generation retirements are driven by unit age-limits and announced retirements, consistent with Reference scenario
- Carbon regulations limiting CO2 emissions will commence in 2025 and remain in effect throughout the forecast horizon
- Portfolios achieves Net Zero by 2050 without any incremental goals and assuming an $100/ton (nominal) offset is available

Scenario Narrative: High Market Price Variant (changed)

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An AEP Company

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
High Market Price Variant	High	Varied	Varied	Varied	Base	Base

High Market Price Variant

The Market Driven Electrification scenario assumes an increase in economic activity drives load higher than the Reference scenario, resulting in increased energy market prices. Commercial and residential customers accelerate the transition to full electrification and continued installation of demand side resources.

In the Market Driven Electrification scenario:

- The Market Driven Electrification scenario will be addressed in Step 4, Analyze Candidate Portfolios.
- The IRP team will use the stochastic simulations to identify the impact of high load conditions on all Candidate Portfolios.

FEEDBACK AND DISCUSSION

STAKEHOLDER SESSION

Stakeholder Session

- The purpose of this session is to allow stakeholders to discuss and propose different strategies to meet load obligations over the next 20 years.
- We won't be able to run a least-cost portfolio run for each strategy, but we will optimize several different strategies.

Process:

1. Open Discussion
2. Poll – based upon the discussion, what additional strategy would you like to see included in the IRP process.
3. In the next meeting, strategies will be defined as model structures
4. Structures will be consolidated into several portfolios for further evaluation

Questions to Facilitate the Discussion

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1. When you consider our IRP objectives of Affordability, Sustainability, and Reliability, is there an alternative strategy that would emphasize a particular objective?

2. In the short-term, what alternative option would you like to see added to the analysis?

3. Over the long-term, should a different strategy be introduced into the analysis?

STAKEHOLDER PROCESS

Stakeholder Timelines

March 9, 2021
- 2021 IRP Process
- Objectives and Metrics
- Proposed Scenarios
- Base Case Inputs

April 14, 2021
- DSM IRP Inputs and Modeling
- EE/EWR, DR and DER Results
- 2021 IRP Update

June 24, 2021
- AURORA Technical Workshop

July 27, 2021 (this session)
- IRP Process – Inputs, Scenarios and Sensitivities
- All-Source RFP Results

August 24, 2021
- Candidate Portfolio Review
- Stochastic Modeling Approach and Assumptions
- Stochastic Modeling

September 21, 2021
- Probabilistic Modeling Results
- Review of Preferred Portfolio
- Other(s)

All-Source RFP Timeline

- **March 26:** Draft RFP Available
- **April 9:** RFP Stakeholder Meeting
- **April 23:** Issue RFP
- **May 21:** Responses Due

AURORA Licensing and Data Provision

Licensing of Aurora Application

- As part of the Stakeholder engagement, I&M executed an agreement to extend licenses of Energy Exemplar's AURORA application to the parties in Case No. U-20591 and to the stakeholders in Indiana that are highly involved in the technical aspects of the IRP.
- As of this meeting, licenses have been issued. Any licensing issues should be reported to Jay Boggs (jay.boggs@siemens.com) or Christen Blend (cmblend@aep.com)
- Online help manuals are available within the Aurora application - the model's Help menu features material like a user manual.

AURORA Licensing and Data Provision (continued)

Data Provision

- Consistent with prior I&M Integrated Resource Planning processes, we will continue to provide access to data to support stakeholder review of the IRP process.
- Siemens will host a confidential and secure site for stakeholders to access the information.
- IRP databases would include input and output tables used in the modeling and will require an NDA with Siemens.
- The model database will be available for review, but Siemens will not provide any review support beyond clearly-defined naming conventions (data key).
- Process for signing up to access the data will be shared by the Stakeholder Meeting #3B in August.

FEEDBACK AND DISCUSSION

CLOSING REMARKS

NIPSCO's 2019 Request for Proposals Results

NIPSCO

CRA Charles River Associates

February 18, 2020

Agenda

- Introduction
- Request for Proposals (“RFP”) Overview
- RFP Results Summary
- Post RFP Next Steps

Webinar Introduction

- Welcome to this webinar for the Northern Indiana Public Service Company's ("NIPSCO") Request for Proposals ("RFP")
- Today's presentation is being made by representatives of Charles River Associates, the independent RFP Manager
- In order to best facilitate today's discussion, we are asking that you use the "Messages" feature in the lower left corner of the webinar to ask questions
  – Please type your question at any point and it will be read to the audience by the facilitator
  – When entering your question, please include your name and organization you are representing (if applicable)
- You may also email questions to **NIPSCO_IRP@NiSource.com** and those questions will be answered as they are received
- If time permits, we will have an open discussion after the material has been presented
- We look forward to your thoughts and questions!

Agenda

- Introduction
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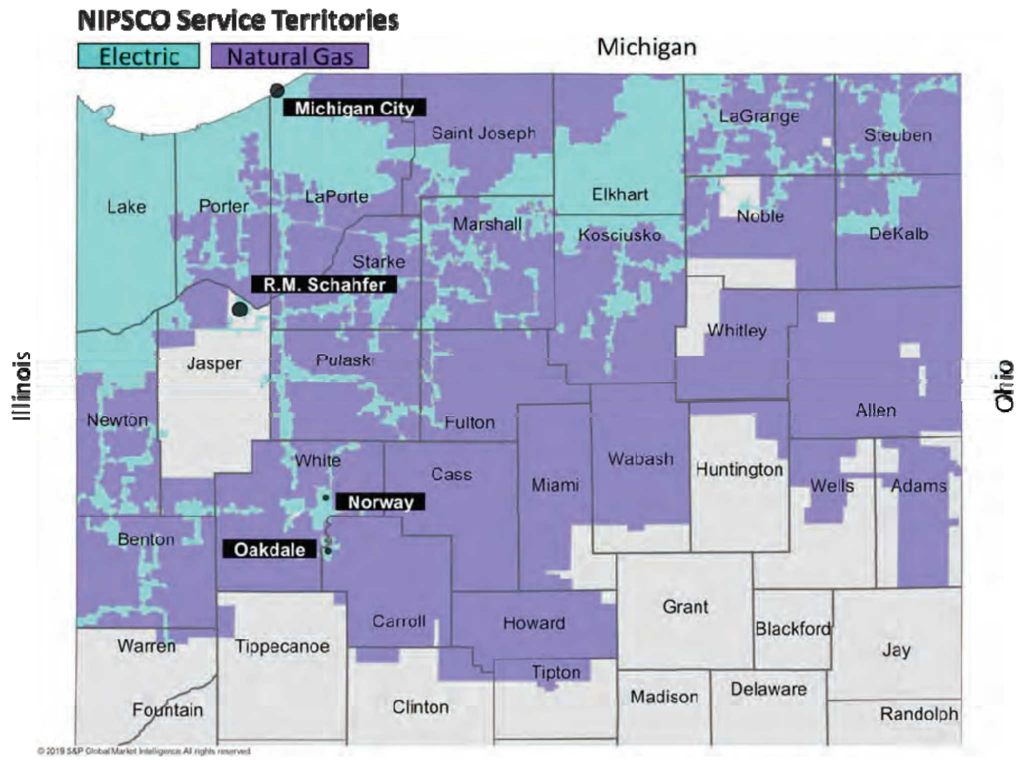
NIPSCO Overview and Their 2018 & 2019 RFP Processes

- NIPSCO does business in the State of Indiana as a regulated public utility generating, transmitting and distributing electricity for sale in Indiana and the broader Midcontinent Independent System Operator, Inc. ("MISO") regional electricity market
- NIPSCO currently serves approximately 468,000 electric customers in northern Indiana
- NIPSCO's 2018 Integrated Resource Plan ("IRP") update identified a 'Preferred Plan' calling for the addition by 2023 of approximately 1,485 megawatts ("MW" – "Unforced Capacity") of solar, wind, DSM and purchases



- In 2018/19, NIPSCO sought and received Indiana Utility Regulatory Commission ("IURC") approval for three wind projects in support of a portion of the identified resource requirements; A fourth approval has been requested by the company and is currently pending
- NIPSCO executed three 2019/20 RFP, to satisfy their remaining capacity needs through proposals for asset sales or power purchase agreements ("PPA"); Resources could be offered as stand-alone assets or paired storage

NIPSCO's IRP and RFP Overview

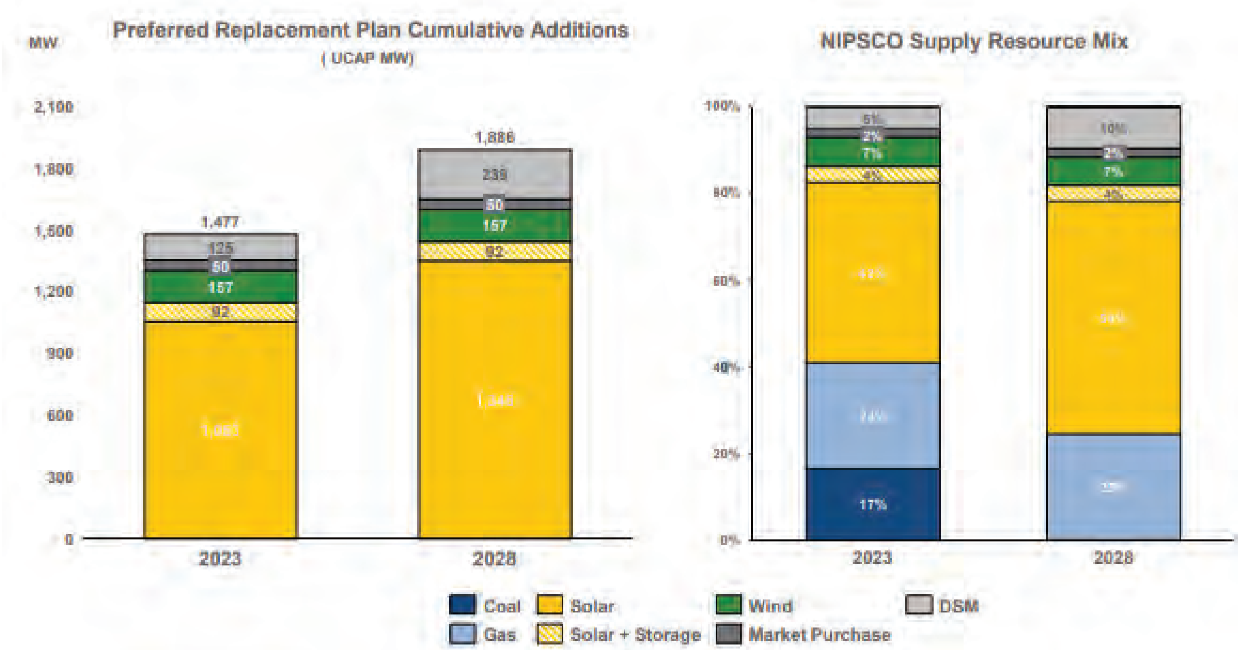
- In 2018, NIPSCO released an update to the 2016 IRP with a Preferred Plan of capacity resources

By 2023, the Preferred Plan calls for:

~1,150 MW UCAP of solar or solar paired with storage

~160 MW UCAP of wind

~175 MW UCAP of other resources including DSM and market purchases



- In 2018, NIPSCO executed an RFP process that successfully sourced a portion of the identified resource requirements
- Through three 2019/20 RFPs, NIPSCO sought to satisfy its remaining capacity needs under the Preferred Plan and ensure an adequate level of reliable generation supply for its customers
  - Event 1 targeted ~ 300 MW* (ICAP) of Wind / Wind Paired with Storage
  - Event 2 targeted ~ 2,300 MW* (ICAP) of Solar / Solar Paired with Storage
  - Event 3 targeted economic opportunities for Thermal / Other capacity resources

RFP Timeline and Milestones

Activity	Date
☑ Notice of Intent w/ Pre-Qualification Documents Due	Wednesday, October 16, 2019
☑ Notification of Pre-Qualification	Monday, October 21, 2019
☑ Proposals Due	Wednesday, November 20, 2019
☑ Start of Bid Evaluation Period	Monday, November 25, 2019
☑ Preliminary Bid Evaluation Completed	Friday, January 10, 2020
☐ **Summary of Bid Results Presented at Webinar**	**Tuesday, February 18, 2020**
☐ **Definitive Agreements Signed with Bidders**	**February – December 2020**

Key Design Elements of the Three 2019/20 RFPs

Technology	• All solutions regardless of technology
Size	• Separate targets by resource class (wind, solar, other) • Targets based on IRP “Preferred Plan” but without specific MW cap by resource • Allows smaller resources to offer their solution as a piece of the total need • Also encourages larger resources to offer their solution for consideration
Ownership Structures	• Seeking bids for asset purchases (new or existing) and power purchase agreements • Resource must qualify as Midcontinent Independent System Operator (“MISO”) internal generation (not pseudo-tied) or load (demand response or “DR”)
Duration	• Requesting delivery beginning June 1, 2023, but will evaluate deliveries before 2023 • Minimum contractual term and/or estimated useful life of 5 years
Deliverability	• Must have firm transmission delivery to MISO Zone 6 • Must meet N-1-1 reliability criteria or show cost estimate to achieve that quality
Participants & Pre-Qualifications	• Marketed RFP to broad bidder audience via trade press and Bidder Conference • Platts Megawatt Daily, North American Energy Marketers Association (NAEMA), NIPSCO Press Release • Required credit-worthy counterparties to ensure ability to fulfill resource obligation

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Agenda

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Participating Bidders – Thank You!

Inovateus Solar

Geronimo Energy
a nationalgrid company

Development Partners

APEX Clean Energy

edp renováveis

S·POWER
An AES and AIMCo Company

Solar Pack

Gale Head Development

PNE
pure new energy

EDF renewables

NextEra Energy

ALLETE clean energy

lightsource bp

EmberClear

Invenergy

Hecate Energy

ORION
Renewable Energy Group LLC

LCE
Lincoln Clean Energy

ibV energy partners

Rockland Capital

Origis Energy
Powering the Solar Revolution

Clēnera
Renewable Energy

ORIDEN
An MHPS Venture

juwi

Tenaska

Solar Energy Systems

Open Road Renewables

St. Joseph energy center

Ranger Power

JMS
Johnson-Melloh Solutions

telamon
simplifying business

esVolta

CPower

Solar Provider Group

Constellation.
An Exelon Company

GlidePath

engie

Duke Energy.

Core Solar

Primary Energy

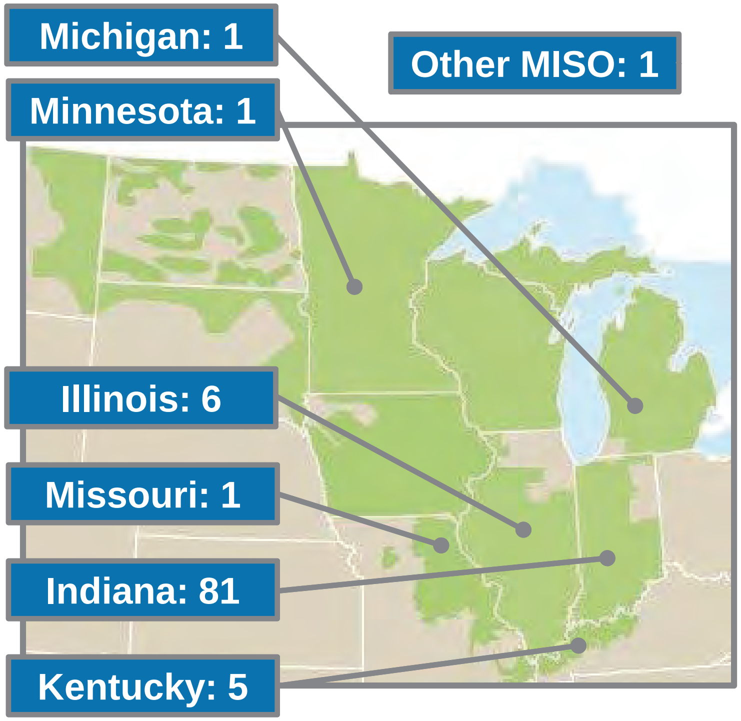
NIPSCO

CRA Charles River Associates

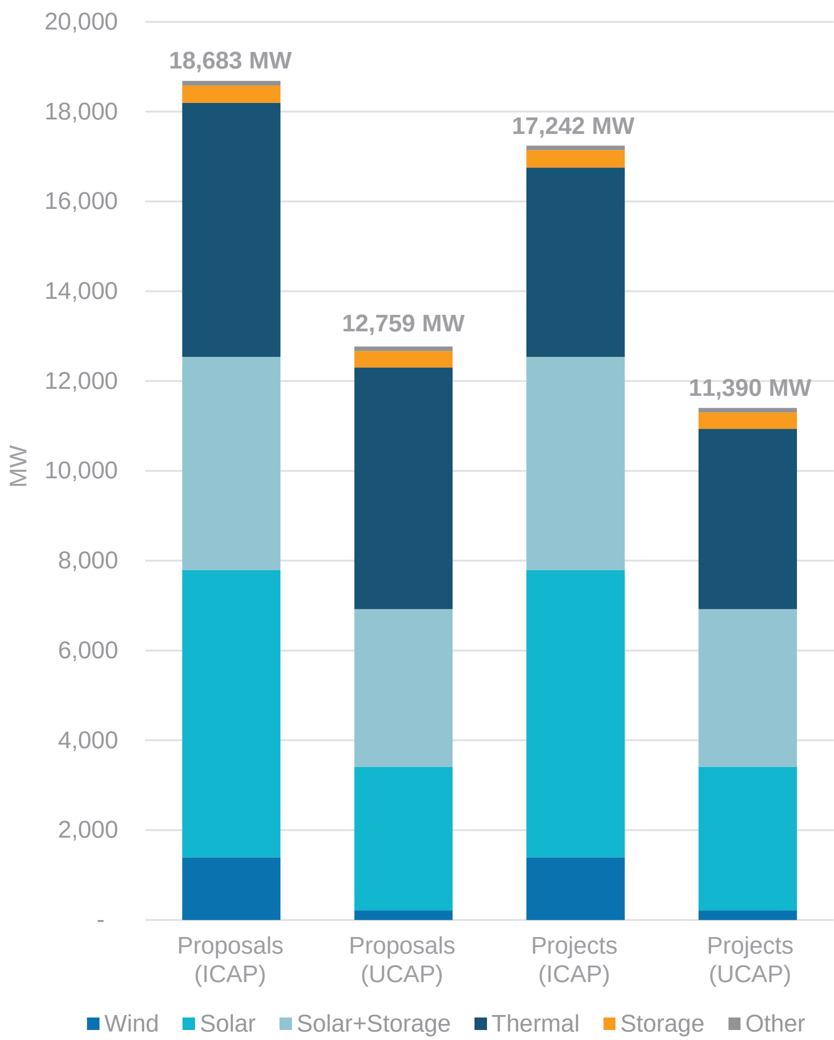
Overview of Proposals Received

- The RFP generated tremendous bidder interest, including 96 total proposals were received across a range of deal structures
  - 93 individual projects across six states with ~17.2 gigawatts (“GW”) (installed capacity “ICAP”) represented
  - Many of the proposals offering variations on pricing structure and term length
  - Several instances of renewables paired with storage
  - Majority of the projects are in various stages of development

Technology	Proposal Count by Structure				
	Asset Sale	PPA	Option	Total	Location
Combined Cycle Gas Turbine (CCGT)	3	4	1	8	IN,MI,IL
Combustion Turbine (CT)	1		2	3	IN
Other/Other Fossil		4		4	IN,MISO
Wind		3	4	7	IL, IN, MN
Solar	1	23	24	48	IN, KY, MO
Solar + Storage		8	15	23	IN, KY
Storage		3		3	IN
Total	5	45	46	96	



Proposal and Project Capacity by Technology (MW)



Technology	ICAP by Project		ICAP by Proposal	
	(MW)	%	(MW)	%
Wind	1,391	8%	1,391	7%
Solar	6,404	37%	6,404	34%
Solar + Storage	4,743	28%	4,743	25%
Thermal	4,216	25%	5,657	30%
Storage	388	2%	388	2%
Other	100	1%	100	1%

Technology	UCAP by Project		UCAP by Proposal	
	(MW)	%	(MW)	%
Wind	197	2%	197	2%
Solar	3,202	28%	3,202	25%
Solar + Storage	3,510	31%	3,510	28%
Thermal	4,013	35%	5,382	42%
Storage	368	3%	368	3%
Other	100	1%	100	1%

Note: Unforced capacity ("UCAP") MW are estimated using MISO class averages by technology

Proposal Pricing by Technology & Structure

- UCAP MW were estimated using MISO class averages by technology

Ownership Structures	Capacity (MW "UCAP") of Proposals by Technology								
	Combined Cycle Gas Turbine (CCGT)	Combustion Turbine (CT)	Other Fossil	Wind	Solar	Solar + Storage	Storage	Other	Total
Asset Sale	2,100	489	-	-	50	-	-	-	2,638
Power Purchase Agreement (PPA)	1,082	-	245	62	810	1,323	368	100	3,990
Option	679	787	-	146	2,343	2,187	-	-	6,142
Total	3,861	1,276	245	209	3,202	3,510	368	100	12,770
Locations	IN, MI, IL	IN	IN, MISO	IN, IL, MN	IN, KY, MO	IN, KY	IN	IN	

Note: Totals may not appear to foot due to rounding

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Proposal Pricing by Technology & Structure

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Wind	4	976	4	976	$1,494.73	$/kW	
	Solar	25	4,785	25	4,785	$1,299.50	$/kW	
	Solar + Storage	15	3,150	15	3,150	$1,120.51	$/kW	
	Thermal	7	4,268	4	2,827	$876.69	$/kW	Fuel cost additional
Power Purchase Agreement (PPA)	Wind	3	415	3	415	$37.10	$/MWh	Some are not LRZ6
	Solar	23	1,619	23	1,619	$39.30	$/MWh	
	Solar + Storage	8	1,593	8	1,593	$43.30	$/MWh	
	Thermal	7	1,389	7	1,389	$5.44	$/kW-mo	Plus fuel and O&M
	Storage	3	388	3	388	$11.18	$/kW-mo	
	Other	1	100	1	100			
	Total	96	18,683	93	17,242			

Note: Totals may not appear to foot due to rounding

- Average bid prices shown for 'Asset Sale or Option' represent capital costs and exclude on-going fuel, O&M and CapEx (where applicable)
- Figures shown are for representation and do not purport a competition between technologies; Separate short-listed assets were created for each RFP event

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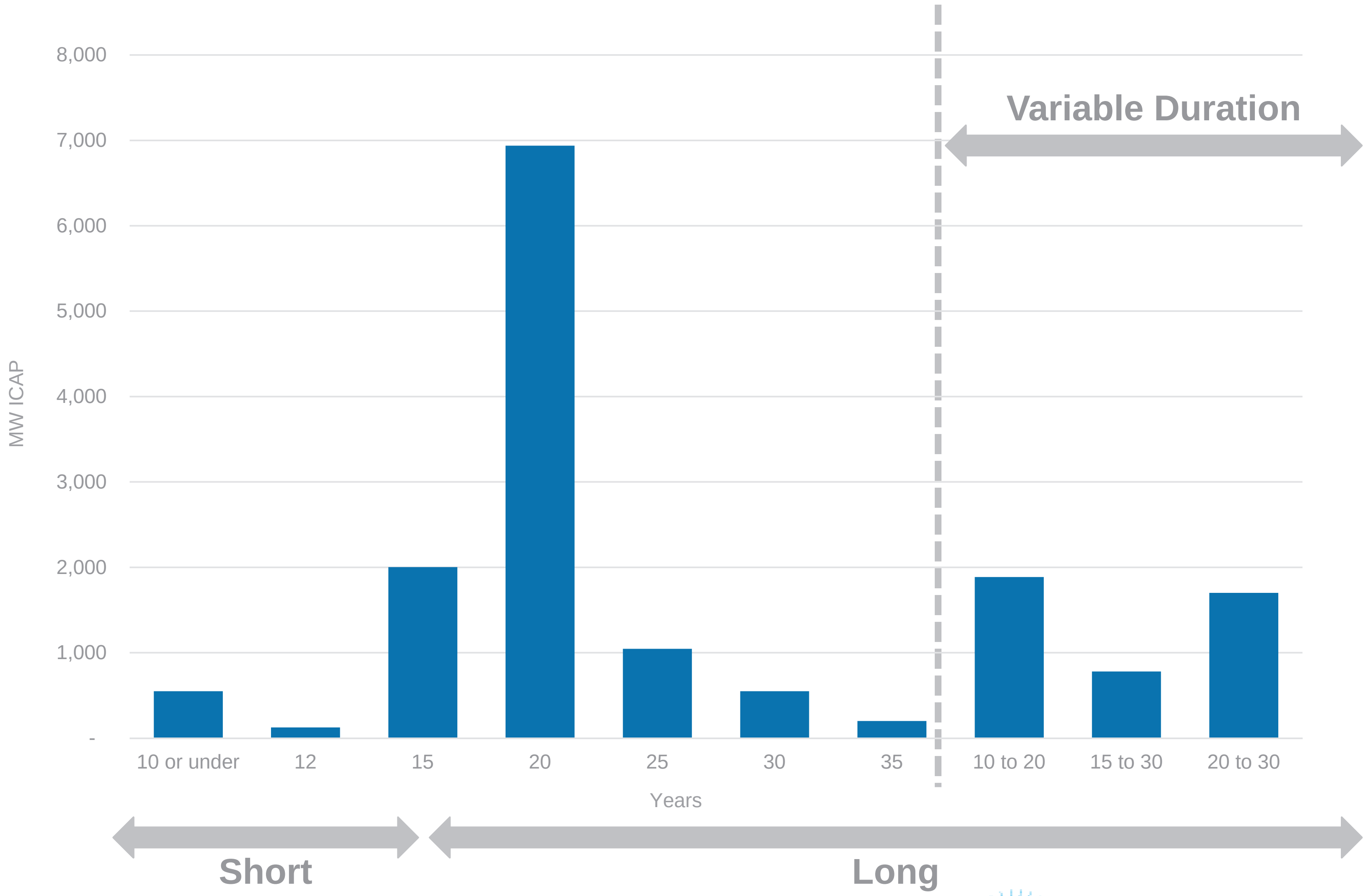
PPA Proposals by Durations



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RFP Evaluation Process

- All Proposals were evaluated consistent with the Evaluation Criteria provided in Appendix F to each RFP
- The RFP evaluated individual proposals and selected the proposals to advance to the final negotiation phase based on certain evaluation criteria:
  - Levelized Cost of Energy (“LCOE”) for the capacity asset
  - Reliability and deliverability
  - Development status
  - Asset-specific benefits and risks

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Post RFP Next Steps

1 Proposal Evaluation & Contract Negotiations

- As part of the bid evaluation, certain proposals were advanced to the final negotiation of definitive agreements ("DA")
- During the final negotiation phase of the process, NIPSCO will undertake certain due diligence including:
  - Site inspections and engineering assessment
  - Management interviews
  - Legal and regulatory due diligence
  - Dispatch modeling (as necessary)
  - Negotiation of final terms and conditions
- NIPSCO may at its sole discretion terminate negotiations at any time or choose to execute definitive agreements with only a subset of finalists

2 Regulatory Approvals

- Any DA(s) would be subject to the granting of a Certificate of Public Convenience and Necessity ("CPCN") by the IURC
- Agreements may require approval in other jurisdictions or at the Federal Energy Regulatory Commission, depending on the nature of the agreement or the asset(s) selected
- Any regulatory filing(s) would begin after the conclusion of NIPSCO's due diligence and the execution of definitive agreements; as such, any DA(s) are subject to regulatory approval

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Q&A Session

- Following the prepared presentation, questions received during the presentation will be answered in the following order:
  - "Messages" feature on the webinar
  - Email (NIPSCO_IRP@NiSource.com)
- After questions sent via "Messages" and email are answered and if time permits, the phone line will be opened for callers with any remaining questions
- Thank you for your interest in the NIPSCO RFPs!

NIPSCO CRA Charles River Associates

Exhibit AG-16
Case No. U-20530
August 24, 2021
Page 1 of 1

Exhibit IM-7 (HAB-7)

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on June 2020 Load Forecast
(2021/2022 - 2025/2026)

		Obligation to PJM							Resources								I&M Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
				=(1)+(2)				=((3)-((4)*(5)))*(6)			=(8)-(9)						=(13)+(14)-(7)	=(13)+(14)+(15)-(7)	=[(7)+((4)*(5)*(6))]/(1+(19))		=(17)/(18)	=(19)+(20)
Planning Year		Internal Demand (a)	DSM (b)	Net Internal Demand	Interruptible Demand Response (c)	Demand Response Factor	Forecast Pool Req't (d)	Total UCAP Obligation	ICAP Existing Capacity & Planned Changes(e)	ICAP Net Capacity Sales (f)	Net ICAP	Incremental Planned Capacity Additions (ICAP) Units	MW	Annual UCAP Purchases	UCAP Existing Capacity (f,g)	UCAP Planned Additions Capacity	Net Position w/o New Capacity	Net Position w/ New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2021 /22	(h)	3,596	0	3,596	204	1.000	1.0870	3,687	4,619	14.7	4,604	South Bend Solar	20		4,444	10	756	767	3,396	15.10%	22.58%	37.68%
2022 /23	(h)	3,681	0	3,681	204	1.000	1.0867	3,778	4,619	14.0	4,605	Solar & Wind	430		4,444	114	666	780	3,481	14.90%	22.40%	37.30%
2023 /24	(h)	3,735	0	3,735	204	1.000	1.0860	3,835	3,711	10.5	3,700	Solar & Wind	300	42	3,585	209	(208)	1	3,533	14.80%	0.03%	14.83%
2024 /25		3,838	(3)	3,835	204	1.000	1.0860	3,943	3,711	6.2	3,705			146	3,590	209	(208)	1	3,628	14.80%	0.02%	14.82%
2025 /26		3,814	(3)	3,812	204	1.000	1.0860	3,918	3,711	6.8	3,704	Solar	150	44	3,589	285	(285)	0	3,606	14.80%	0.01%	14.81%

Notes:
(a) Based on June 2020 Load Forecast (with implied PJM diversity factor)
(b) Existing plus approved and projected "Passive" EE, and VVO. DSM is included in the PJM forecast.
(c) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR
(d) Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)
(e) Reflects the members ownership ratio of following summer capability assumptions:
I&M PPR share of OVEC
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
FGD DERATES:
RETIREMENTS & LEASE END:
Rockport 2 - Lease Ends 12/07/2022; capacity assumed to be extended to 5/31/2023
Rockport 1 - 12/07/2022 Unit Power agreement with KPCo ends, I&M receives 100% of Unit 1.
(f) Includes Offset from Anderson/Frankton load and IMPA Capacity transfer, capacity sales, and excess commitment credits.
(g) Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year
(h) PJM forecast

2023/2024 RPM Base Residual Auction Planning Period Parameters

Introduction

The planning parameters for the 2023/2024 RPM Base Residual Auction (BRA) that is to be conducted in December of 2021 were posted on the PJM RPM website on August 23, 2021. This document describes the posted parameters and provides a comparison to the 2022/2023 BRA planning parameters.

PJM RTO Region Reliability Requirement

The PJM RTO forecast peak load, the PJM RTO Region Reliability Requirement and the parameters used to derive the requirement for the 2023/2024 BRA are shown and compared to the 2022/2023 BRA parameters in Table 1.

The forecast peak load for the PJM RTO for the 2023/2024 Delivery Year is 150,504 MW which increased by 275 MW, or 0.2% compared to the forecast peak load of 150,229 MW for the 2022/2023 BRA. The forecast PJM system peak load is that reported in Table B-10 of the January 2021 RPM update of the PJM Load Forecast Report.[1] The PJM RTO Reliability Requirement for the 2023/2024 Delivery Year is 163,493 MW which increased by 224 MW, or 0.1% compared to the 2022/2023 BRA value prior to adjustment for FRR obligation of 163,269 MW.[2]

The Installed Reserve Margin (IRM) and Forecast Pool Requirement (FPR) represent the level of capacity reserves needed to satisfy the PJM reliability criterion of a Loss of Load Expectation not exceeding one occurrence in ten years. The IRM and FPR represent the same level of required reserves but are expressed in different terms of capacity value. The IRM expresses the required reserve level in terms of installed capacity MW (ICAP) as a percent of the forecast peak load, whereas the FPR expresses the required reserve level in terms of unforced capacity MW (UCAP) as a percent of the forecast peak load. The FPR is equal to (1 + IRM) times (1 - Pool-wide Average EFORd). The PJM RTO Reliability Requirement expressed in terms of unforced capacity is used as the basis of the target reserve level to be procured in each RPM BRA and is equal to the forecast RTO peak load, multiplied by the FPR.

[1] The 2021 RPM Forecast is located at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx.

[2] The total UCAP Obligation of all Fixed Resource Requirement (FRR) Entities is subtracted from the PJM RTO Reliability Requirement, and any applicable LDA Reliability Requirement, when determining the target reserve levels to be procured in each RPM BRA. The posted 2023/2024 BRA planning parameters will be updated to reflect the total UCAP Obligation of FRR Entities after FRR Capacity Plans are submitted and reviewed in November 2021.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Table 1 – Reserve Requirement Parameters for 2022/2023 and 2023/2024 BRAs

Reserve Requirement Parameters	2022/2023 BRA	2023/2024 BRA	Change in Value	Change in Percent
Installed Reserve Margin (IRM)	14.50%	14.40%	-0.10%	-0.7%
Pool Wide 5-Year Average EFORd	5.08%	5.04%	-0.04%	-0.8%
Forecast Pool Requirement (FPR)	1.0868	1.0863	-0.0005	0.0%
Forecast Peak Load (MW)	150,229	150,504	275	0.2%
PJM RTO Reliability Requirement (UCAP MW)	**163,269**	**163,493**	**224**	**0.1%**
FRR Obligation (UCAP MW)*	31,012			
PJM RTO Reliability Requirement adjusted for FRR (UCAP MW)	132,257			

*The 2023/2024 BRA PJM RTO Reliability Requirement will be updated to reflect FRR load in November 2021.

Locational Deliverability Areas

Prior to each BRA, the Capacity Emergency Transfer Objective (CETO) and Capacity Emergency Transfer Limit (CETL) are calculated for each of twenty-seven potential Locational Deliverability Areas (LDAs) that are defined in Schedule 10.1 of the PJM Reliability Assurance Agreement.[3] Pursuant to Section 5.10 of Attachment DD of the PJM Open Access Transmission Tariff (OATT), for any Delivery Year, a separate Variable Resource Requirement (VRR) Curve is established for each LDA for which (1) the CETL is less than 1.15 times its CETO; (2) the LDA had a Locational Price Adder in any one or more of the three immediately preceding BRAs; and (3) the MAAC, EMAAC and SWMAAC LDAs are modeled in a BRA regardless of the outcome of the CETL/CETO test or prior BRA results. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that such LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

Based on an application of the above criteria, a separate VRR Curve will be established for the 2023/2024 BRA for each of the LDAs listed in Table 2. The list includes the same LDAs that were modeled with a separate VRR Curve in the 2022/2023 BRA. Of the LDAs listed on Table 2, the MAAC, EMAAC, ATSI, BGE, ComEd, DEOK and PS LDAs have cleared with a Locational Price Adder in one or more of the past three BRAs. The DPL SOUTH LDA has a CETL to CETO ratio of 1.14, which is less than 1.15 for the 2023/2024 BRA. While none of the other listed LDAs had a Locational Price Adder in any of the last three BRAs or had a CETL to CETO ratio less than 1.15, they will be modeled in order to maintain an acceptable level of reliability consistent with the Reliability Principles and

[3] CETO and CETL values were calculated for each of the twenty-seven potential LDAs defined in Schedule 10.1 of the PJM RAA and these values are shown on the detailed planning parameters spreadsheet posted on the PJM RPM website.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Standards. Establishing a separate VRR Curve for an LDA does not predestine the LDA to clear the BRA with a Locational Price Adder; an LDA will only clear at a higher clearing price if reliability constraints are reached when attempting to import capacity into the LDA in the auction clearing.

A Reliability Requirement and a separate Variable Resource Requirement (VRR) Curve are established for each LDA that is modeled in the BRA and the LDA CETL acts as a maximum limit on the quantity of capacity that can be imported into the LDA. Table 2 shows the Reliability Requirement and the CETL for each LDA being modeled in the 2023/2024 BRA. For comparison purposes, the LDA Reliability Requirement and CETL values used in the 2022/2023 BRA are also shown in Table 2.

Changes in LDA reliability requirement are primarily driven by changes in the forecast peak load of the LDA and changes in the availability rate of capacity resources located in the LDA. The reliability requirement of an LDA will decrease for a decrease in the forecast peak load of the LDA and an increase in the availability rate of capacity resources located in the LDA. The reliability requirement of an LDA will increase for an increase in the forecast peak load of the LDA and a decrease in the availability rate of capacity resources located in the LDA.

Year-over-year changes in the CETL of an LDA are primarily driven by the addition or removal of transmission facilities, the magnitude and location of generation deactivations and generation additions, and changes in load distribution profile within the LDA. LDA CETL values for the 2023/2024 BRA vary significantly in some cases from those of the 2022/2023 BRA in both the upward and downward direction but, in general, the magnitude of the changes for most regions lies within the year-to-year changes historically experienced.

Of those LDAs that had a Locational Price Adder in one or more of the last three BRAs, the MAAC LDA CETL had the largest increase as compared to 2022/2023 and the COMED LDA CETL had the largest decrease as compared to 2022/2023. The MAAC LDA CETL is 2,006 MW higher for the 2023/2024 BRA, a 46% increase from the 2022/2023 BRA CETL. The COMED LDA CETL is 983 MW lower for the 2023/2024 BRA, a 14% decrease from the 2022/2023 BRA CETL.

The increase in MAAC LDA CETL is primarily attributable to the deactivation of the Morgantown generating units for which deactivation notifications were submitted in June of 2021 with a requested deactivation date of May 2022. The removal of nearly 1,230 MW of Morgantown generation from the CETL model reduced the loading on the High Ridge-Sandy Spring 230 kV line which was a limiting transmission facility in the 2022/2023 BRA CETL model. The reduced loading of this circuit allowed for a higher level of imports into the MAAC LDA before this same circuit again limited the LDA CETL in the 2023/2024 CETL model.

2023/2024 RPM Base Residual Auction Planning Period Parameters

The decrease in COMED LDA CETL is primarily attributable to the deactivation of the Waukegan, Will County, and Byron generating units for which deactivation notifications were submitted in June of 2021 with requested deactivation dates of May 2022 for the Waukegan and Will County units and September 2021 for the Byron units. The removal of these generation resources totaling about 3,500 MW from the CETL model resulted in a significantly different flow pattern and different set of transmission facilities that limited imports into the ComEd LDA at a lower CETL level than that of the 2022/2023 BRA CETL.

Table 2 – LDA Reliability Requirements and Capacity Import Limits for 2022/2023 and 2023/2024 BRAs

	2022/2023 BRA		2023/2024 BRA		Delta			
LDA	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (UCAP MW)	CETL (MW)	Reliability Requirement (Percent)	CETL (Percent)
MAAC	64,514.0	4,375.0	64,910.0	6,381.0	396.0	2,006.0	1%	46%
EMAAC	35,884.0	9,173.0	36,125.0	8,704.0	241.0	-469.0	1%	-5%
SWMAAC	14,934.0	8,310.0	14,746.0	8,249.0	-188.0	-61.0	-1%	-1%
PS	11,686.0	8,626.0	11,716.0	8,991.0	30.0	365.0	0%	4%
PS NORTH	6,180.0	4,360.0	6,194.0	4,360.0	14.0	0.0	0%	0%
DPL SOUTH	3,155.0	2,053.0	3,191.0	2,025.0	36.0	-28.0	1%	-1%
PEPCO	7,701.0	6,781.0	7,179.0	7,160.0	-522.0	379.0	-7%	6%
ATSI	15,011.0	9,119.0	15,105.0	9,602.0	94.0	483.0	1%	5%
ATSI-Cleveland	5,761.0	5,229.0	5,620.0	4,962.0	-141.0	-267.0	-2%	-5%
COMED	23,931.0	6,839.0	23,816.0	5,856.0	-115.0	-983.0	0%	-14%
BGE	7,828.0	5,683.0	7,891.0	5,662.0	63.0	-21.0	1%	0%
PL	10,244.0	4,850.0	10,334.0	4,767.0	90.0	-83.0	1%	-2%
DAYTON	3,950.0	3,941.0	4,069.0	4,022.0	119.0	81.0	3%	2%
DEOK	7,407.0	5,465.0	7,528.0	5,641.0	121.0	176.0	2%	3%

Variable Resource Requirement Curves

A Variable Resource Requirement (VRR) curve is established for the RTO and for each LDA modeled in the BRA. The VRR curve is a downward-sloping demand curve used in the clearing of the BRA that defines the price for a given level of capacity resource commitment relative to the applicable reliability requirement. The VRR curves for the PJM Region and each LDA are based on a target level of capacity and the Net Cost of New Entry (Net CONE). As shown on the posted planning parameters and as discussed in the Price Responsive Demand (PRD) section of this report, the VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis to reflect any PRD that has elected to participate in the 2023/2024 Delivery Year BRA.

Target Level of Capacity

In the development of the VRR curve, the target level of capacity to be procured for the PJM RTO Region is the PJM RTO Region Reliability Requirement, and the target level of capacity for each LDA is the LDA Reliability Requirement.

Net Cost of New Entry (CONE)

The Net CONE (in UCAP terms) is used in the development of the RTO VRR Curve and the VRR Curve for each modeled LDA. Table 3 shows the Net CONE values, and the components used to determine the Net CONE, for the PJM RTO and each LDA to be modeled in the 2023/2024 BRA. For comparison purposes, the CONE values used in the 2022/2023 BRA are also shown in Table 3.

The Net CONE for the RTO and each LDA is equal to the gross CONE applicable to the RTO and each LDA minus the applicable net energy and ancillary services ("EAS") revenue offset or forward net energy and ancillary services revenue offset for the 2023/2024 Delivery Year. The Net CONE increased for the RTO and for all of the modeled LDAs. The Net CONE of the RTO increased by 1.2% and the increase in LDA Net CONE values ranged from 1.2% for the RTO LDA to 13.8% for the DAYTON LDA. The increase in Net CONE across all LDAs is due to the escalation in Gross CONE values determined as part of the quadrennial review update and the forward EAS values increasing slightly or decreasing for some LDAs. The Gross CONE values increased in all LDAs, while the calculated Forward Net EAS increased in all LDAs except for the ATSI-CLEVELAND, COMED, PL, DAYTON, and DEOK LDAs. The Net EAS values for the 2023/2024 are shaped using the 2023/2024 forward LMP data on LMPs from calendar years 2018 through 2020 for historical data, whereas the Net EAS values for the 2022/2023 are shaped using the 2022/2023 forward LMP data on LMPs from calendar years 2018 through 2020 for historical data.

2023/2024 RPM Base Residual Auction Planning Period Parameters

Table 3 – Net CONE for PJM RTO and LDAs for 2022/2023 and 2023/2024 BRAs

	2022/2023 BRA				2023/2024 BRA				Change in Net CONE	
Location	Gross CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	Gross CONE ICAP Terms ($/MW-Year)	E&AS Offset ICAP Terms ($/MW-Year)	Net CONE ICAP Terms ($/MW-Year)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms ($/MW-Day)	Net CONE UCAP Terms (%)
RTO	$107,175	$16,924	$90,251	$260.50	$113,866	$22,205	$91,661	$263.73	$3.23	1.2%
MAAC	$107,627	$22,703	$84,925	$245.12	$111,814	$23,288	$91,306	$262.71	$17.59	7.2%
EMAAC	$108,000	$18,144	$89,856	$259.36	$115,314	$19,791	$95,522	$274.84	$15.48	6.0%
SWMAAC	$109,700	$25,530	$84,173	$242.95	$116,598	$29,517	$87,082	$250.56	$7.61	3.1%
PS, PS NORTH	$108,000	$14,997	$93,003	$268.44	$115,314	$17,275	$98,039	$282.08	$13.64	5.1%
DPL SOUTH	$108,000	$26,173	$81,827	$236.18	$115,314	$29,989	$85,324	$245.50	$9.32	3.9%
PEPCO	$109,700	$19,786	$89,914	$259.52	$116,598	$22,991	$93,607	$269.33	$9.81	3.8%
ATSI, Cleveland	$105,500	$25,642	$79,858	$230.50	$111,737	$21,279	$90,458	$260.27	$29.77	12.9%
COMED	$105,500	$19,626	$85,874	$247.86	$111,737	$15,467	$96,270	$276.99	$29.13	11.8%
BGE	$109,700	$31,273	$78,427	$226.37	$116,598	$36,043	$80,555	$231.78	$5.41	2.4%
PL	$105,500	$18,744	$86,756	$250.41	$111,814	$16,586	$95,228	$273.99	$23.58	9.4%
DAYTON	$105,500	$27,090	$78,410	$226.32	$111,737	$22,212	$89,525	$257.59	$31.27	13.8%
DEOK	$105,500	$28,023	$77,477	$223.63	$111,737	$23,965	$87,772	$252.54	$28.91	12.9%

Price Responsive Demand (PRD)

Price Responsive Demand is provided by a PJM Member that represents retail customers having the ability to automatically reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year.

In order to commit PRD for a Delivery Year, a PRD Provider must submit a PRD Plan by August 6th preceding the BRA for such Delivery Year that demonstrates to PJM's satisfaction that the nominated amount of PRD will be available by the start of the Delivery Year and that the Plan satisfies all requirements as described in section 3A of PJM Manual18: PJM Capacity Market.[4] A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the Capacity Exchange system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. Once committed in a BRA, a PRD

[4] PRD Providers must submit a PRD Plan by January 15th preceding the BRA for such Delivery Year during normal BRA scheduled auctions.

commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

As shown in the 2023/2024 Planning Parameters, 235 MW of PRD across the RTO has elected to participate in the 2022/2023 BRA: 87 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 38 MW in the EMAAC LDA (with 15.4 MW located in the DPL-South LDA). By comparison, 230 MW of PRD elected to participate in the 2022/2023 BRA: 80 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 40 MW in the EMAAC LDA (with 19.6 MW located in the DPL-South LDA).

Summary

- The forecast peak load for the PJM RTO for the 2023/2024 Delivery Year is 150,504 MW which is 275 MW, or 0.2%, above the forecast peak load of 150,229 MW for the 2022/2023 BRA.

- The PJM RTO Reliability Requirement for the 2023/2024 Delivery Year is 163,493 MW which is 224 MW, or 0.1%, above the 2022/2023 BRA value prior to adjustment for FRR obligation. The Reliability Requirement will be updated to include FRR load in November 2021.

- The MAAC, EMAAC, SWMAAC, PS, PSNORTH, PEPCO, DPLSOUTH, ATSI, Cleveland, ComEd, BGE, PPL, DAYTON, and DEOK LDAs will be modeled in the 2023/2024 BRA. These are the same LDAs that were modeled in the 2022/2023 BRA.

- 235 MW of PRD across the RTO has elected to participate in the 2023/2024 BRA: 87 MW in the BGE LDA, 110 MW in the PEPCO LDA, and 38 MW in the EMAAC LDA (with 15.4 MW located in the DPL-South LDA).

- With energy efficiency now explicitly reflected in the peak load forecast, the Reliability Requirement of the RTO and each affected LDA will be increased by the total UCAP value of all EE Resources for which PJM accepts an Measurement and Verification Plan for the BRA. PJM will post updated planning parameters to reflect these quantities prior to the opening of the auction window.

Interconnection Process Reform Task Force Update

Jason Connell
Infrastructure Planning
Planning Committee
May 11, 2021

Task Force Update

- First meeting was April 23
  - Education – existing interconnection process summary
  - Review the work plan
    - Targeting completion by year end
  - Interest identification
    - Study Process
    - Cost Concerns
    - Interim Operation/Agreements
    - Application requirements

Backlog Update

- PJM is reprioritizing its interconnection queue work
  - AG1 System Impact Studies will remain on schedule for August
  - AG2 Feasibility Studies will be postponed until at least January 2022
  - Staff will shift focus to backlogged studies
  - Staff augmentation over the next six months
- Next IPRTF meeting is June 1, 2021

PJM Interconnection Queue Status Update

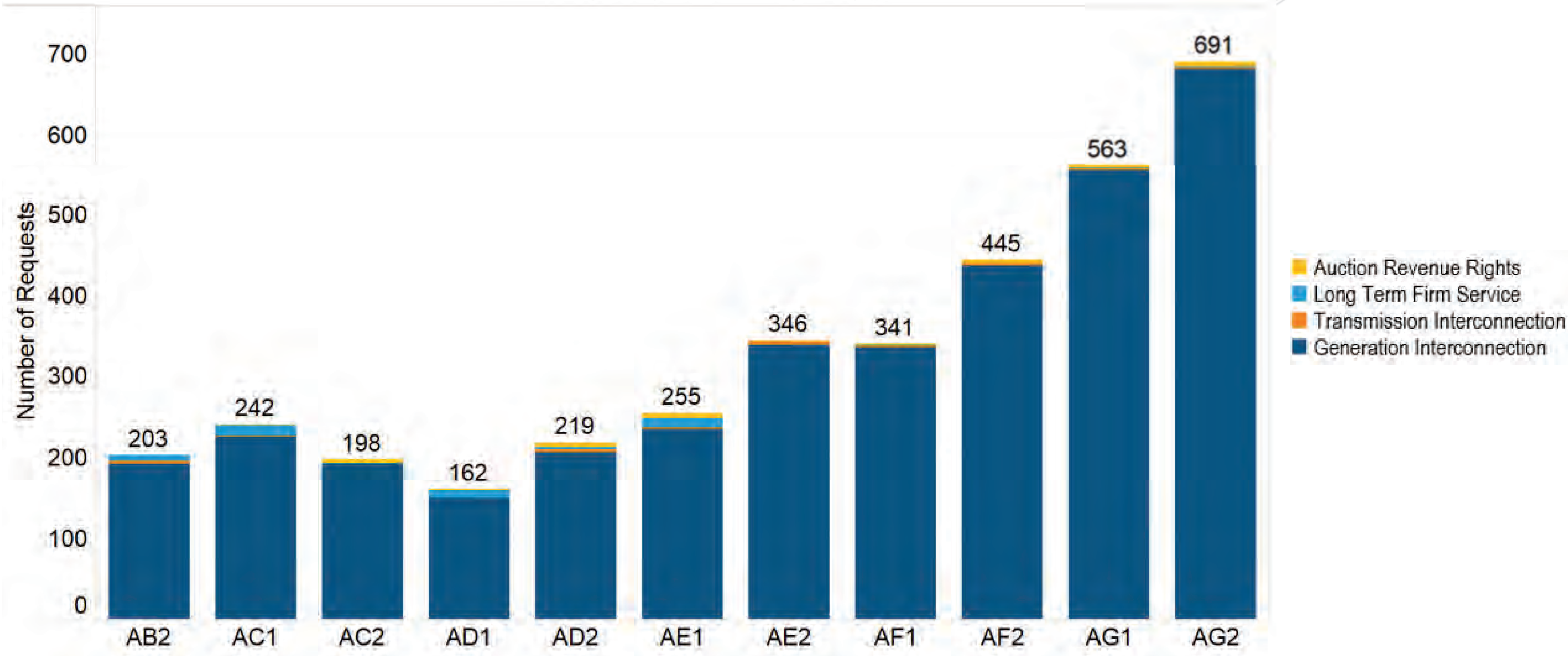
Onyinye Caven
Interconnection Projects
Planning Committee
May 11, 2021

Overview

- Queue Trends: AB2 (November 2015) – AG2 (March 2021)
- AG2 Queue Overview

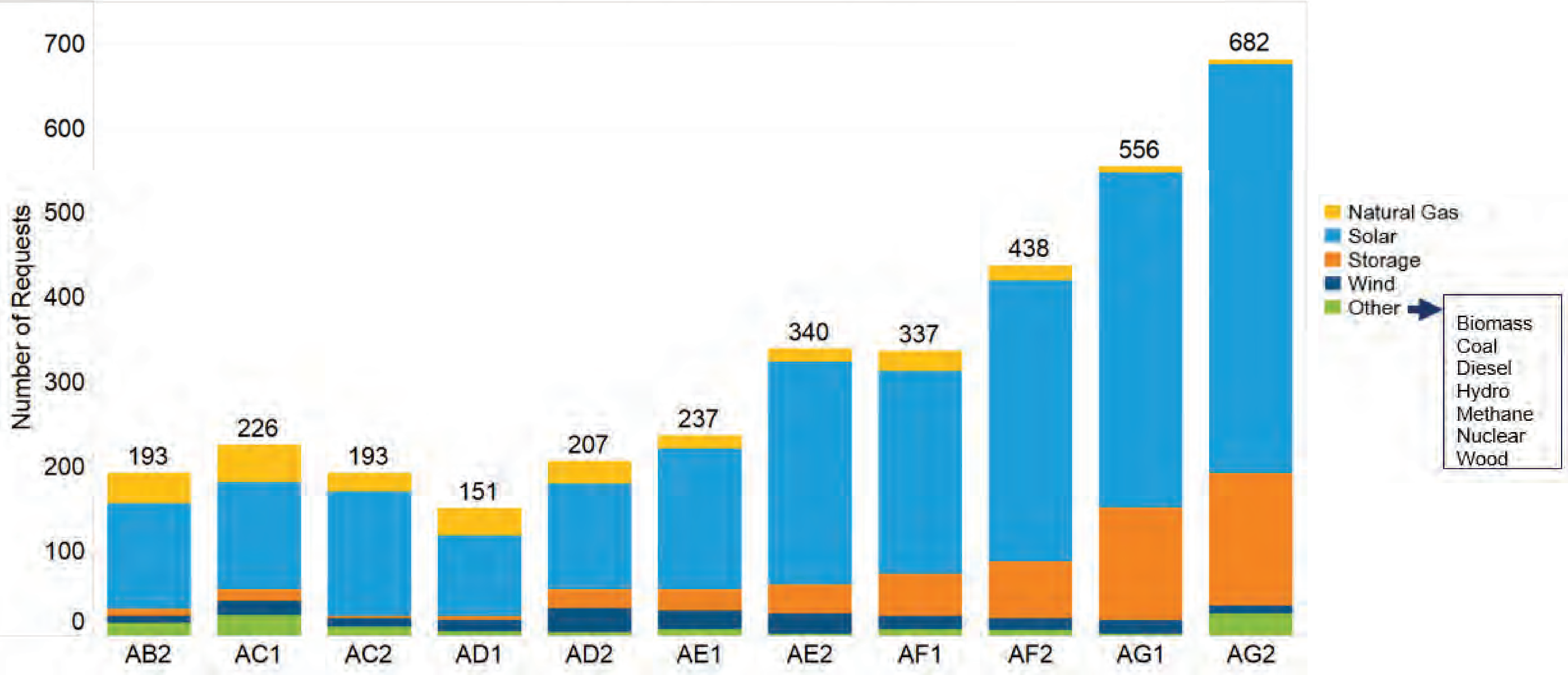
Note: Data provided is a snapshot of the Interconnection Queue as of April 30, 2021

Recent Queue Trends: AB2 – AG2
Total New Service Requests by Application Type



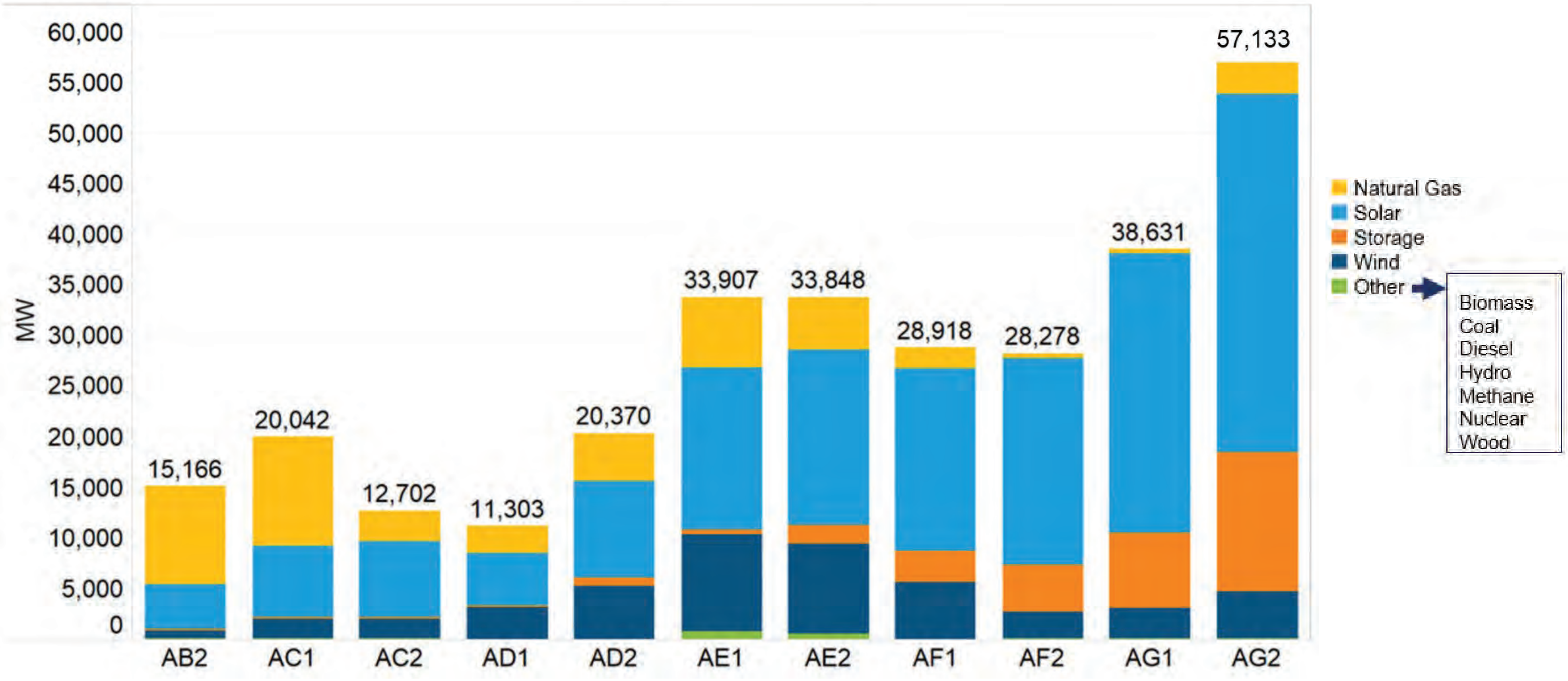
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Total Number



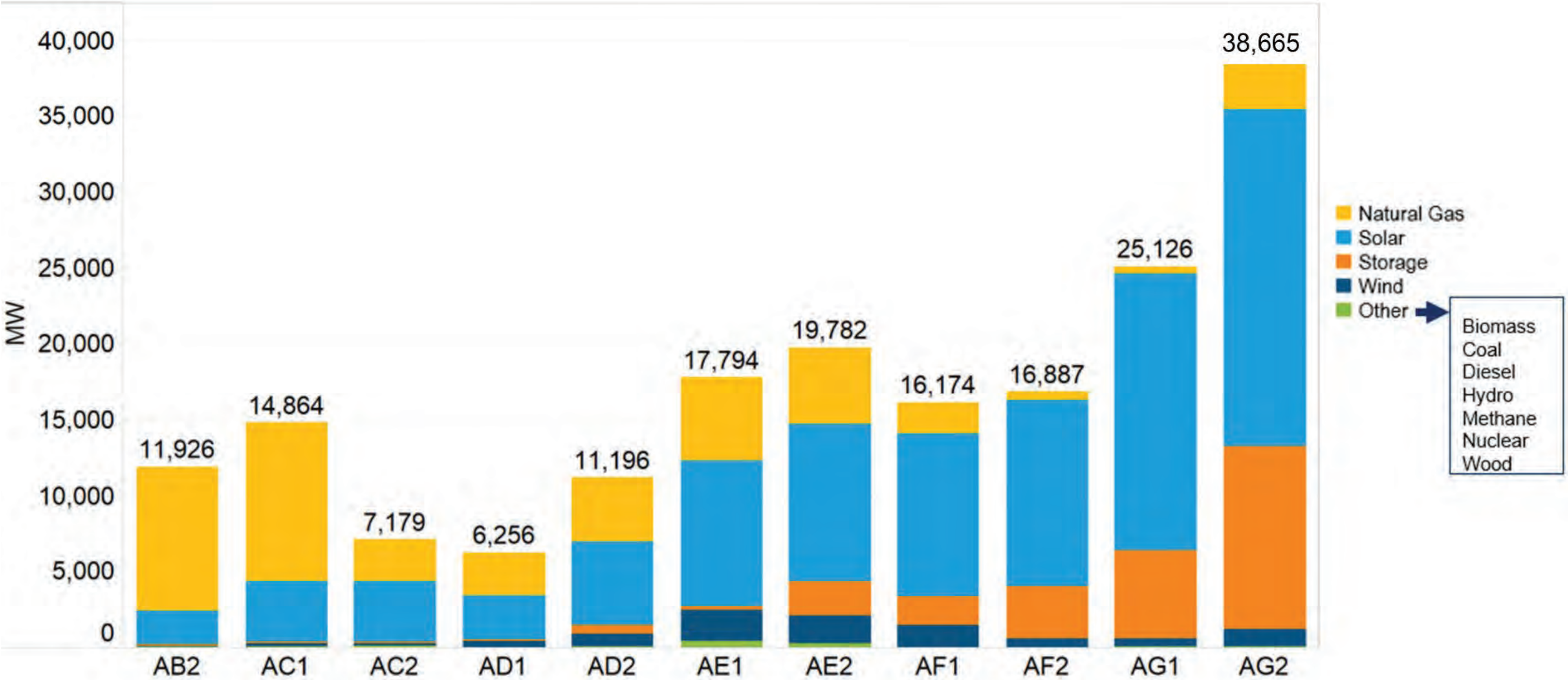
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Requested Energy



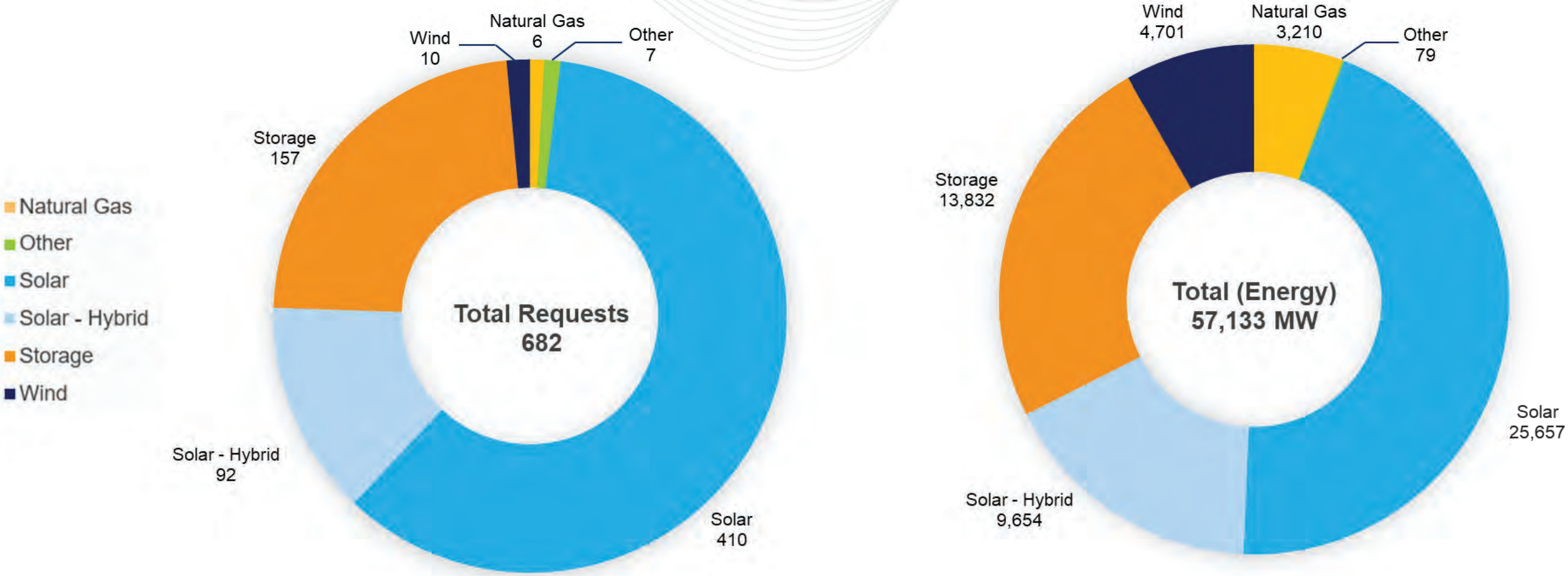
Recent Queue Trends: AB2 – AG2

Generation Interconnection Requests – Requested CIRs



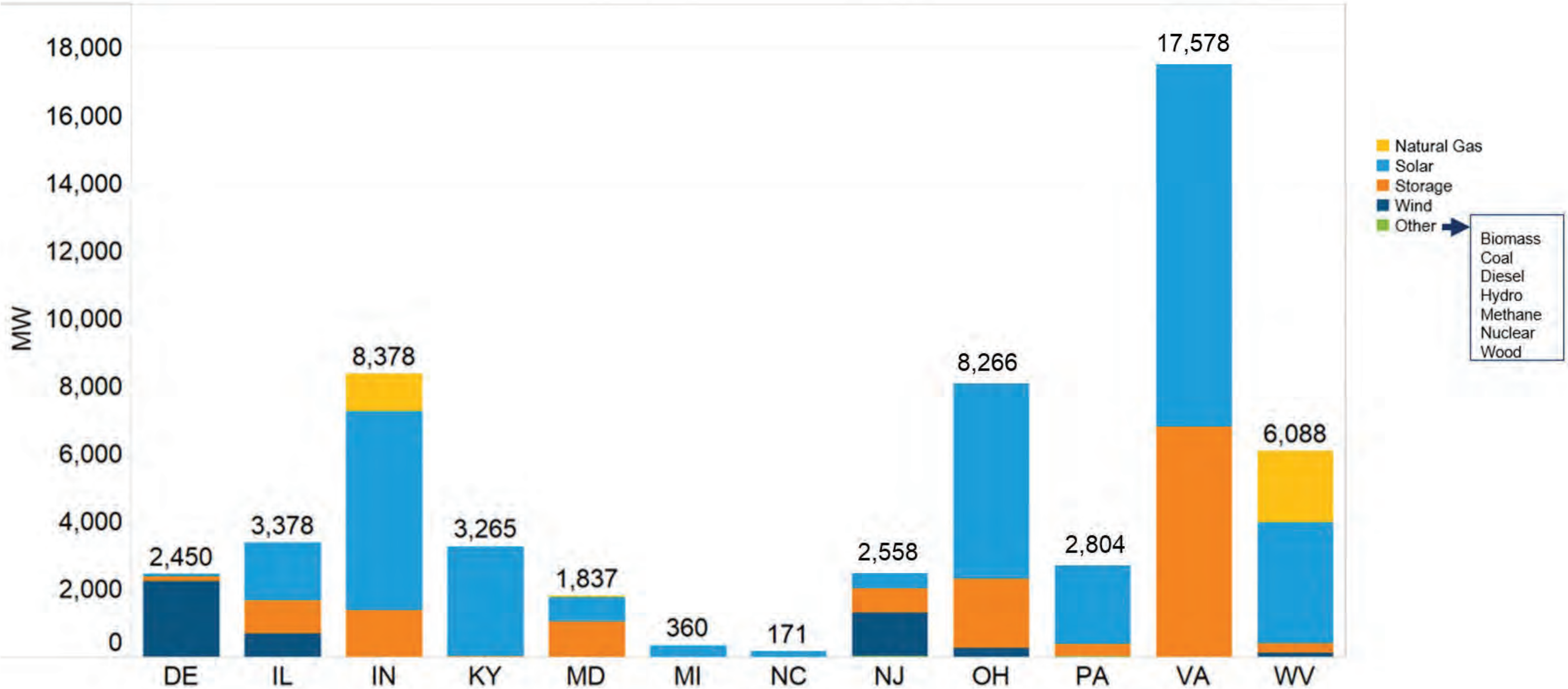
AG2 Queue Overview
(Generation Interconnection Requests)

AG2 Queue Overview
Generation Interconnection Requests by Fuel Type



AG2 Queue Overview

All Fuel Types by State - Requested Energy



A – AG2 Queue and Active Queue Projects

Generation Phase Progression: A – AG2
All Generation Requests

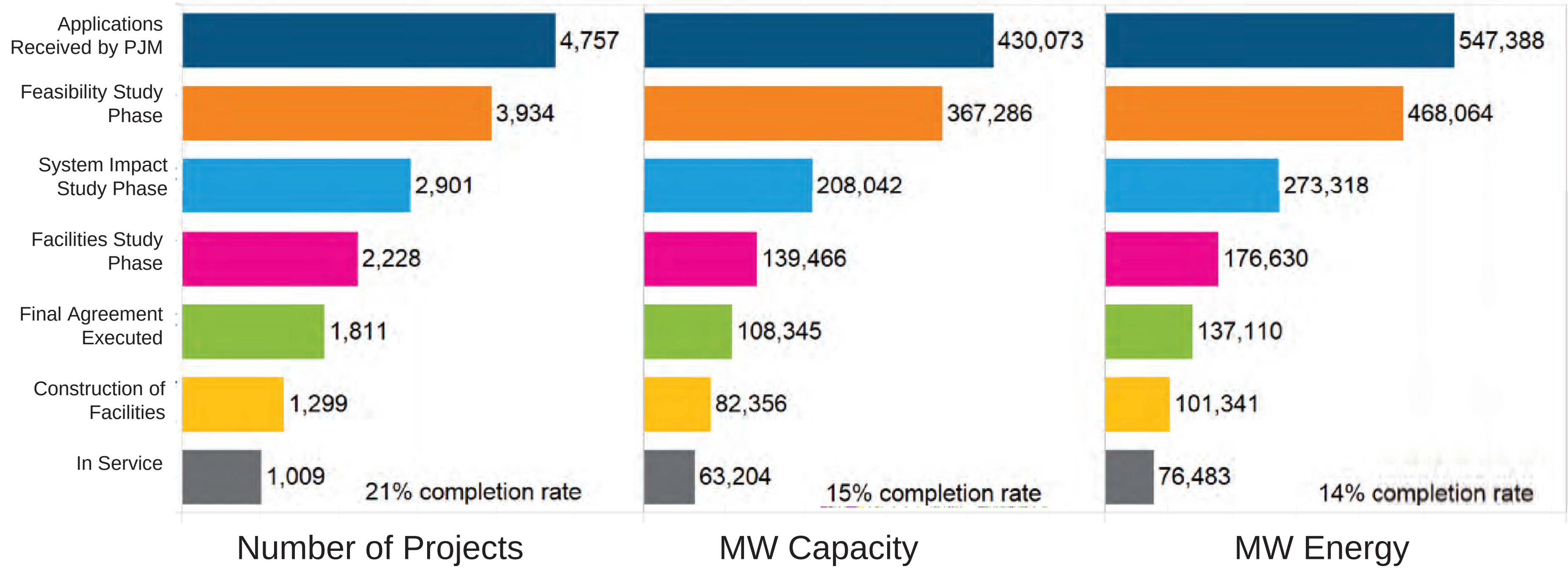
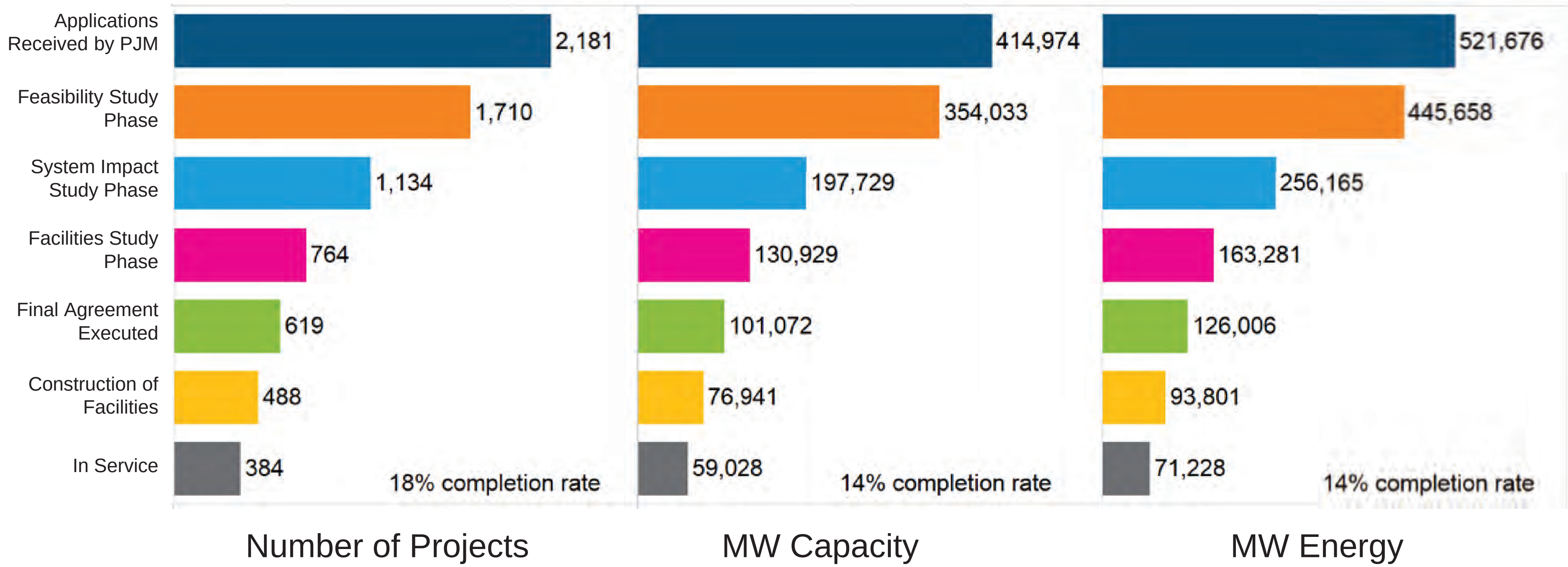
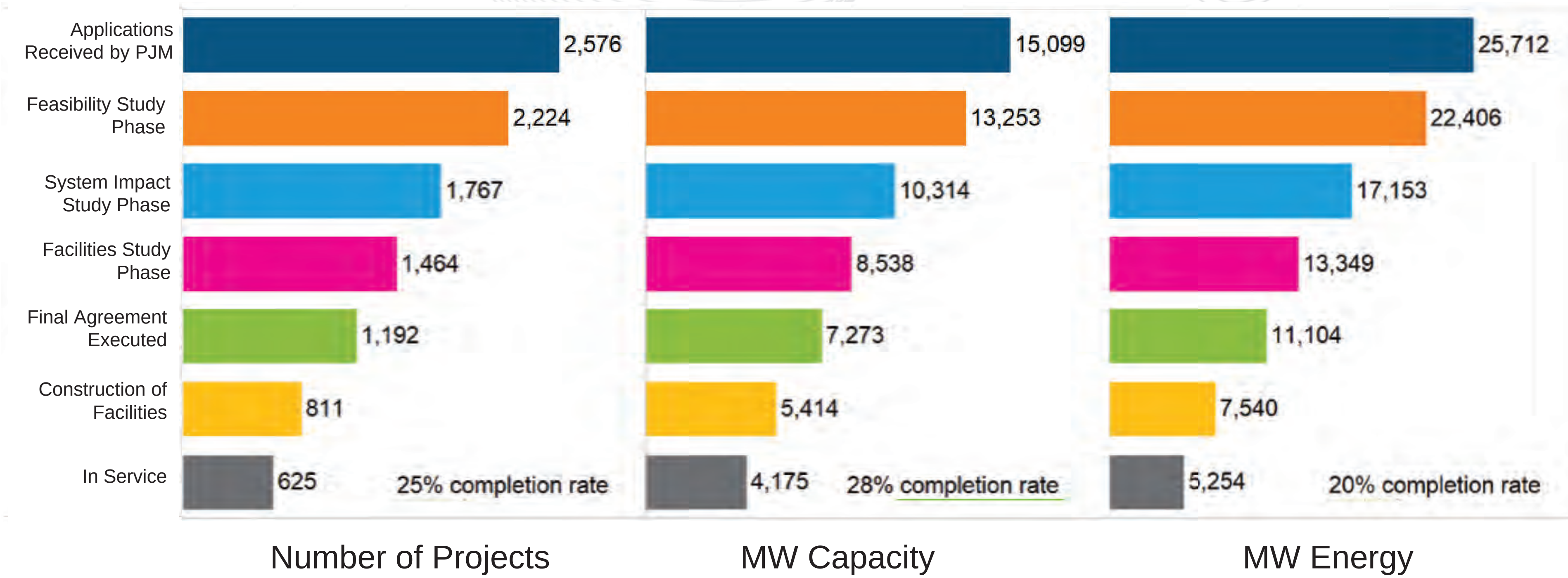


Exhibit AG-18
Case No. U-20530
August 24, 2021

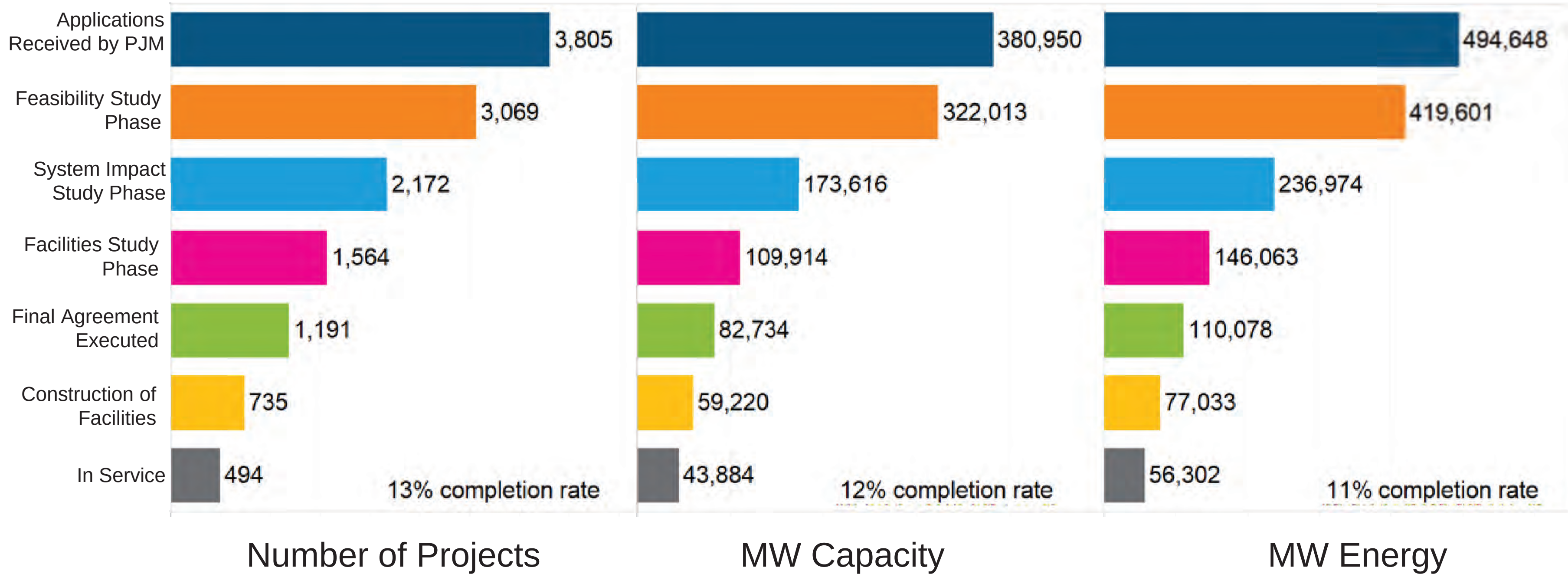
Generation Phase Progression: A – AG2
Large Generation Requests (> 20 MW)



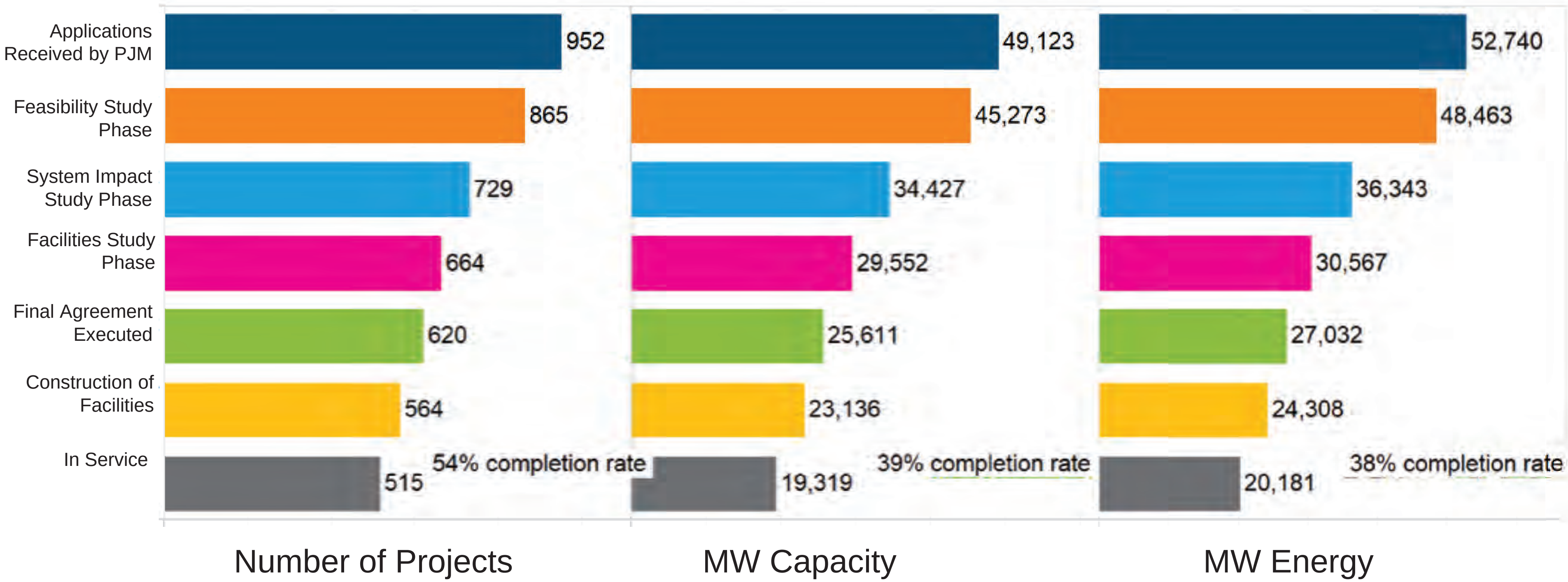
Generation Phase Progression: A – AG2
Small Generation Requests (≤ 20 MW)



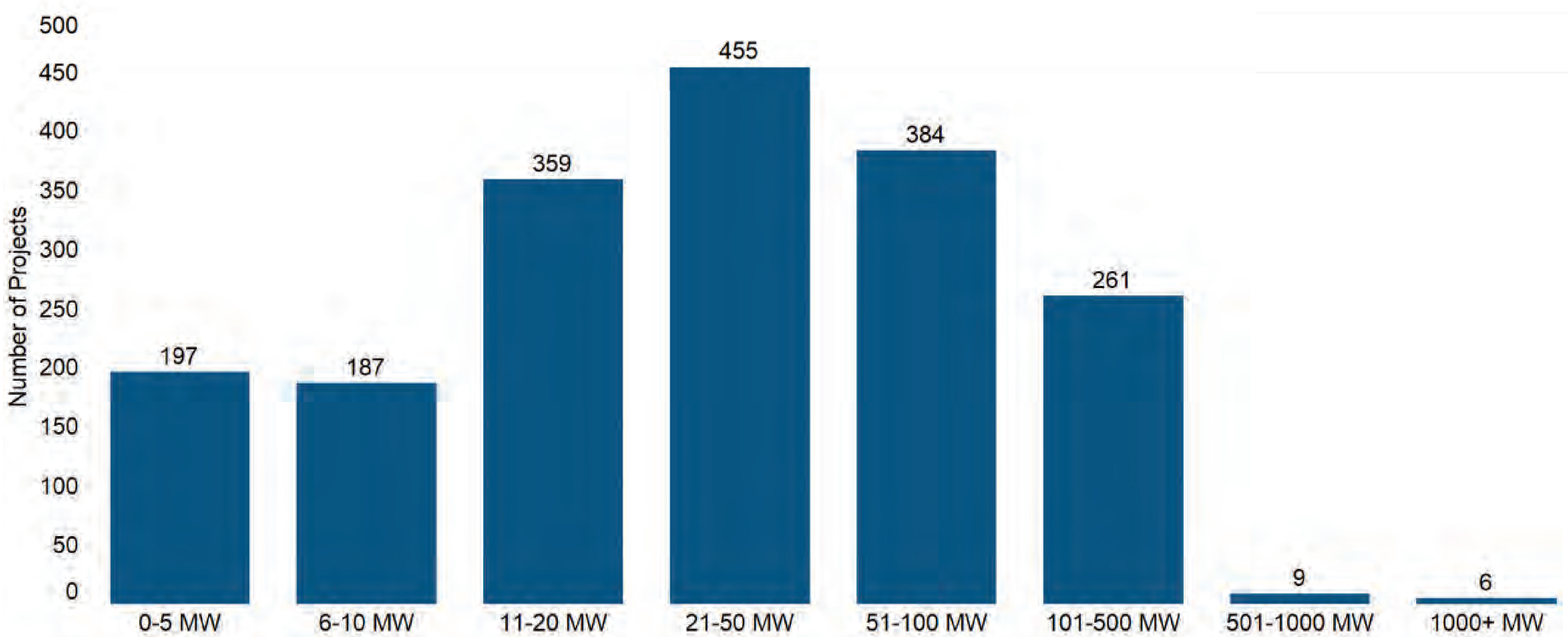
Generation Phase Progression: A – AG2 New Facility Requests



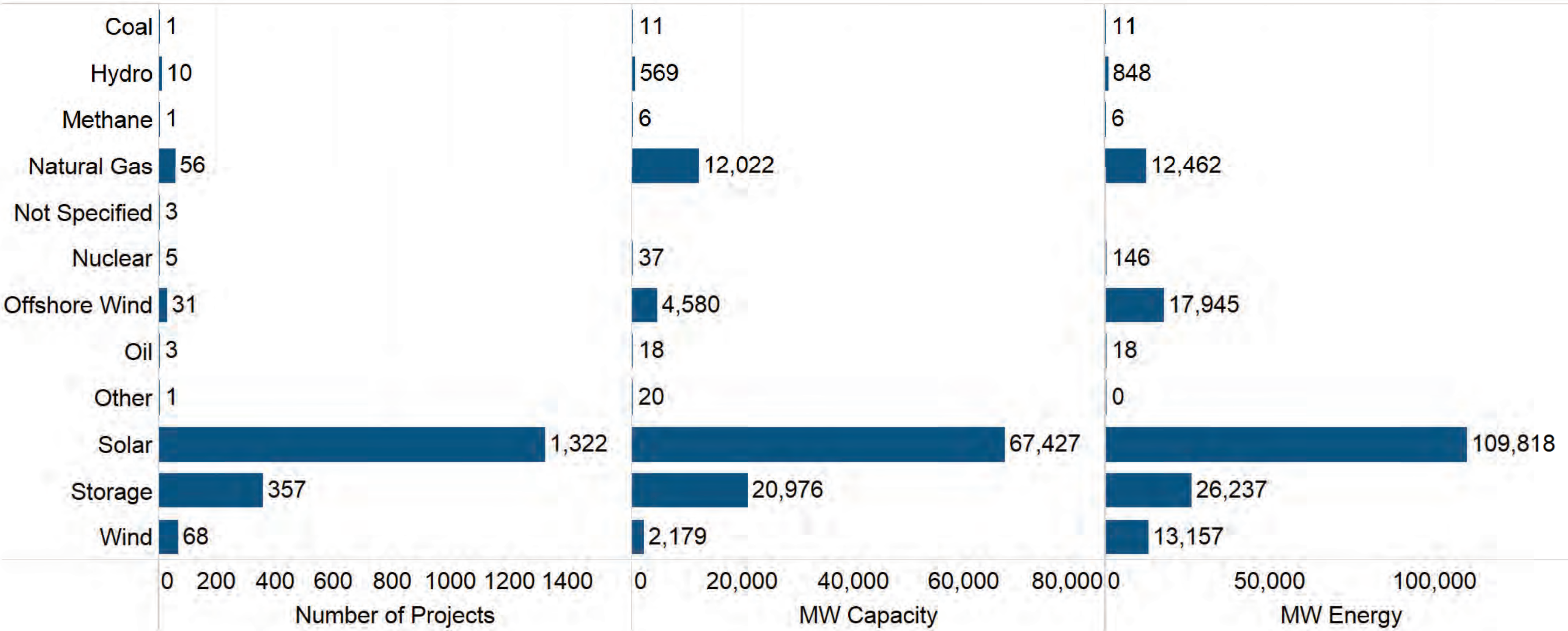
Generation Phase Progression: A – AG2
Uprate Generation Requests



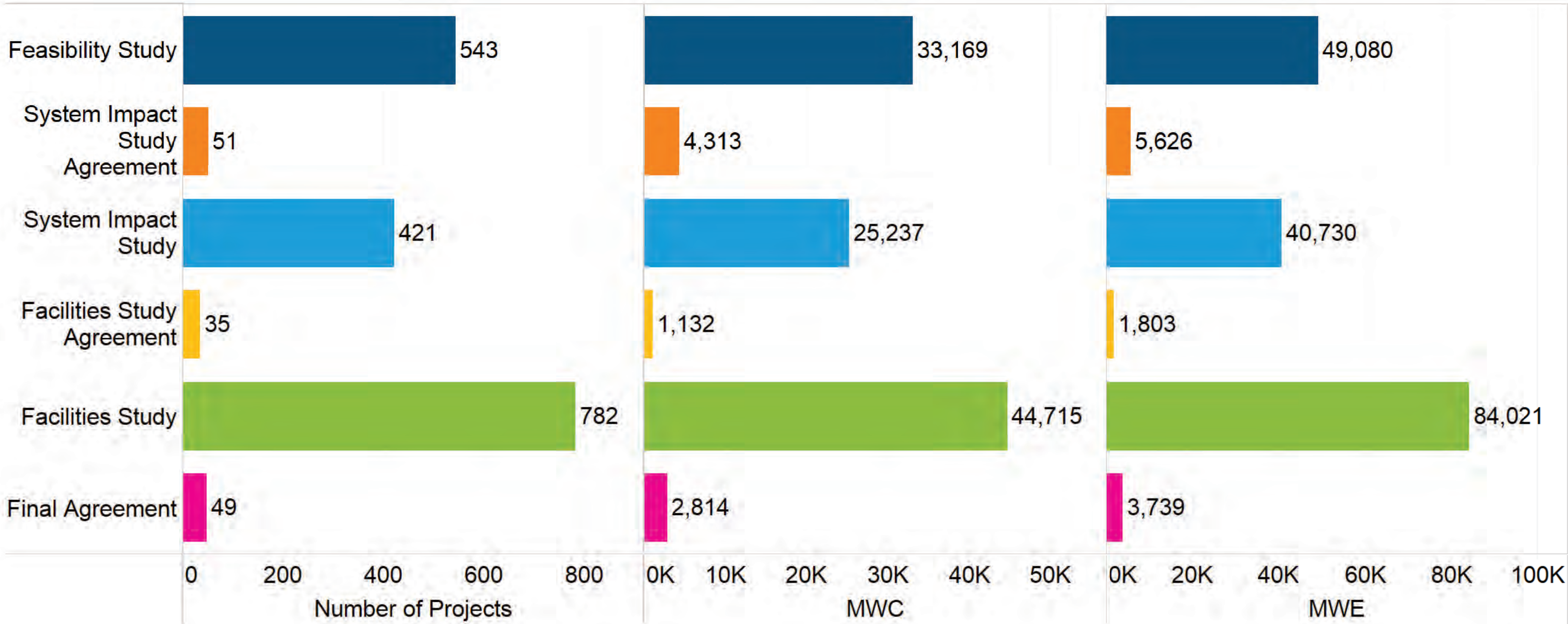
Active Projects in the Queue
Project Size Distribution



Active Projects in the Queue
Fuel Type Distribution

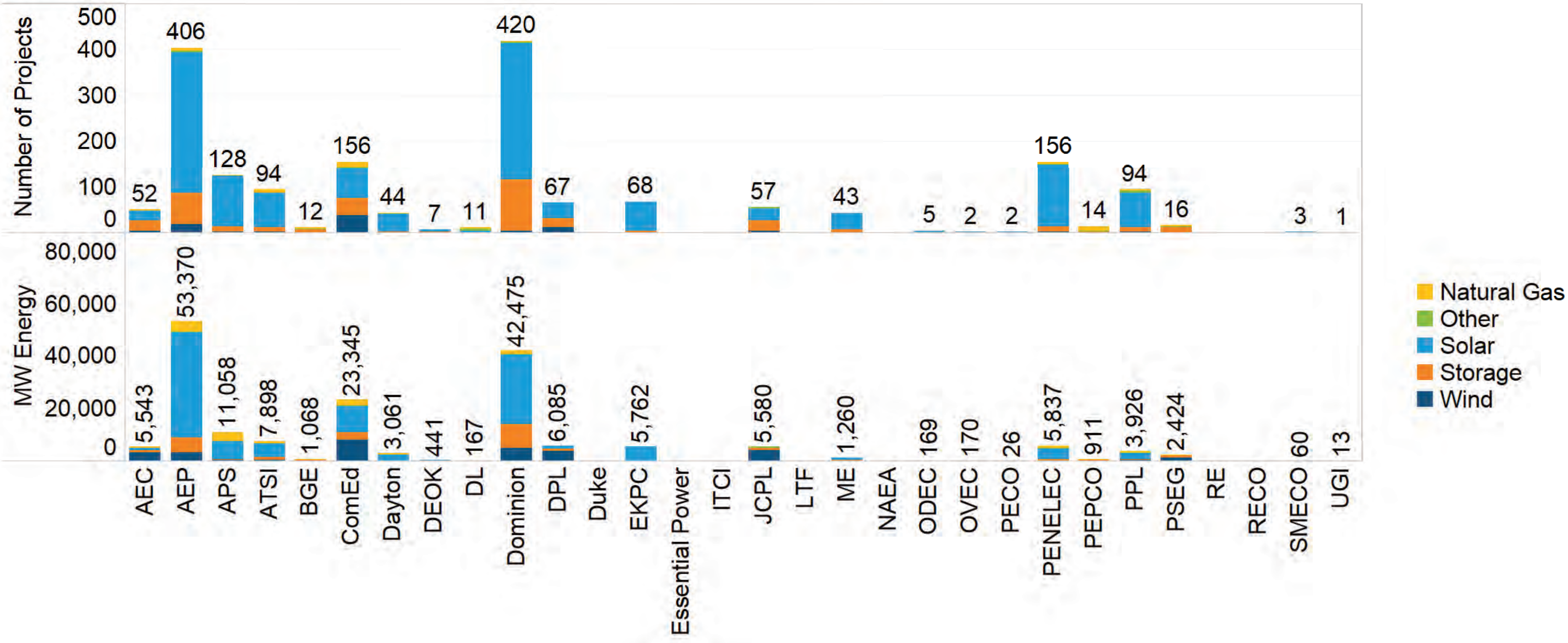


Active Projects in the Queue
Distribution of Study Phases



Active Projects in the Queue

Distribution by Transmission Owner Zone



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PJM Interconnection Queue Status Update

Member Hotline

(610) 666 – 8980

(866) 400 – 8980

custsvc@pjm.com

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge*. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge.* The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs.* To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments.* The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.,* 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver.* Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties.* Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default.* If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________

Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________

Its ______________________

APPALACHIAN POWER COMPANY

By ______________________

Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________

Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________

Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________

Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________

Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________

Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________

Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________

Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ________________________
Its ________________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ________________________
Its ________________________

APPALACHIAN POWER COMPANY

By [signature]
Its ________________________

BUCKEYE POWER GENERATING, LLC

By ________________________
Its ________________________

COLUMBUS SOUTHERN POWER COMPANY

By ________________________
Its ________________________

THE DAYTON POWER AND LIGHT COMPANY

By ________________________
Its ________________________

DUKE ENERGY OHIO, INC.

By ________________________
Its ________________________

FIRSTENERGY GENERATION CORP.

By ________________________
Its ________________________

INDIANA MICHIGAN POWER COMPANY

By ________________________
Its ________________________

KENTUCKY UTILITIES COMPANY

By ________________________
Its ________________________

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Its ____________________

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Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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Its ______________________

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By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By [signature]
Its VICE PRESIDENT

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its VICE PRESIDENT

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By Gary Stephenson
Its EXECUTIVE VICE PRESIDENT
Gary Stephenson

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active 12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By Gary R Leidich
Its President

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active.12026116.4

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OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

LOUISVILLE GAS AND ELECTRIC COMPANY

By [signature]
Its VP Trans. & Generation Services

MONONGAHELA POWER COMPANY

By ____________________
Its ____________________

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its ______________________

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its General Manager, Electric Supply

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its ______________________

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By Ronald E. Christian
Its President

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur
Its President

APPROVED AS TO FORM:

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

The Dayton Power and Light Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Ohio Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 1
CASE NO. U-20530

DATA REQUEST NO. 1-09-AG

Request

Identify all actions, if any, that I&M or AEP took during 2020 to limit customers' costs under the OVEC ICPA.

Response

I&M objects to the request on the grounds and to the extent the request mischaracterizes the ratemaking process. Customers pay for service, not for individual components of service under the OVEC ICPA. I&M further objects to this request on the grounds that it is overly broad, unduly burdensome, vague and ambiguous in its use of the term "all actions." Subject to and without waiving these objections, all actions taken by the ICPA sponsoring companies to affect any operations of OVEC must be made through the Operating Committee and require a majority vote by that committee. The Company, through its AEPSC Commercial Operations representative, participated in the Operating Committee meetings during 2020.

As to objection
Counsel

Preparer
Stegall

INDIANA MICHIGAN POWER COMPANY
MICHIGAN DEPARTMENT OF ATTORNEY GENERAL
DATA REQUEST SET NO. AG DR 3
CASE NO. U-20530

DATA REQUEST NO. AG 3-34

Request

Refer to I&M response 1-09-AG and 2-28-AG:

a. Were actions to limit or reduce I&M's costs under the ICPA discussed at the Operating Committee meetings in 2020? If yes, describe in detail.

b. Were any decisions made or actions taken at the Operating Committee meetings in 2020 to limit or reduce I&M's costs under the ICPA in 2020? If yes, describe in detail.

c. If the answer to (a) or (b) is yes, produce the agenda and minutes of the Operating Committee meetings where the actions inquired about were discussed, decisions made, or actions taken; as well as any presentations or handouts from said meetings.

Response

I&M objects to these requests on the basis that the requests are vague and overly broad, particularly to the extent the request does not give any frame of reference or limitation as to what I&M is to compare the 2020 ICPA costs to in order to determine whether the costs were limited or reduced. The Company further objects to this request because it misconstrues the purpose of the Operating Committee. As stated in Section 9.05 of the ICPA, the Operating Committee "shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this agreement, including establishing (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof." Subject to and without waiving these objection, I&M states, in 2020, the Company, through AEP's representatives on the OVEC Operating Committee, participated in the Operating Committee meetings as specified in Section 9.05 of the Intercompany Power Agreement.

As to Objection
Counsel

Preparer
Stegall

UNIT POWER AGREEMENT

THIS AGREEMENT dated as of March 31, 1982 by and between INDIANA & MICHIGAN ELECTRIC COMPANY ("IMECO") and AEP GENERATING COMPANY ("AEGCO"),

WITNESSETH:

WHEREAS, IMECO, a subsidiary company of American Electric Power Company, Inc. ("AEP") under the Public Utility Holding Company Act of 1935 (the "1935 Act"), is presently constructing the Rockport Steam Electric Generating Plant at a site along the Ohio River near the Town of Rockport, Indiana, which will consist of two 1,300,000-kilowatt fossil-fired steam electric generating units and associated equipment and facilities (the "Rockport Plant"), the first unit ("Unit No. 1") of which is presently expected to be placed in commercial operation in 1984 and the second unit ("Unit No. 2") of which is presently expected to be placed in commercial operation in 1986; and

WHEREAS, AEGCO proposes to enter into an Owners' Agreement, dated as of March 31, 1982 (the "Owners' Agreement"), with IMECO and Kentucky Power Company ("KEPCO"), another subsidiary company of AEP under the 1935 Act, pursuant to which AEGCO and KEPCO plan to acquire undivided ownership interests, as tenants in common without right of partition, in the Rockport Plant which, upon completion of the construction of Unit No. 1, is thereafter to be operated as a part of the interconnected, integrated electric system comprising the American Electric Power System (the "AEP System"); and

WHEREAS, AEGCO proposes, upon completion of the construction of Unit No. 1 and the completion thereafter of the construction of Unit No. 2, to make available to IMECO, pursuant to this agreement, all of the available power (and the energy associated therewith) to which AEGCO shall from time to time be entitled at the Rockport Plant; and

WHEREAS, IMECO proposes to complete the construction of, the Rockport Plant pursuant to the provisions of the Owners' Agreement, and, upon completion of such construction, to operate the Rockport Plant pursuant to an operating agreement to be entered into by IMECO, AEGCO and KEPCO in accordance with the Owners' Agreement;

NOW, THEREFORE, in consideration of the terms and of the agreements hereinafter set forth, the parties hereto agree with each other as follows:

1.1 IMECO and AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 and Section 2.2 of this agreement, use their respective best efforts to complete and to make effective the arrangements described and specified in Section 1.1 and in Section 1.2 of the Capital Funds Agreement, dated as of March 31, 1982, between AEP and AEGCO.

1.2 AEGCO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.1 of this agreement, make available, or cause to be made available, to IMECO all of the power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, including test power produced during the course of the construction of generating units installed as a part of the Rockport Plant.

1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments are to commence under this Section 1.3 to be fair, and authorized, by the Federal Energy Regulatory Commission ("FERC", such term also including any successor Federal regulatory agency) as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Public Service Commission of Indiana as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

2.1 The performance of the obligations of AEGCO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities at the time necessary to permit AEGCO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities at the time necessary to permit the completion by IMECO of the construction of the Rockport Plant, the operation of the Rockport Plant, and for AEGCO to make available to IMECO all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant. AEGCO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities.

2.2 The performance of the obligations of IMECO hereunder shall be subject to the receipt and continued effectiveness of all authorizations of governmental regulatory authorities necessary at the time to permit IMECO to perform its duties and obligations hereunder, including the receipt and continued effectiveness of all authorizations by governmental regulatory authorities necessary at the time to permit IMECO to pay to AEGCO in consideration for the right to receive all of the power (and the energy associated therewith) available to AEGCO at the Rockport Plant the charges provided for in Section 1.3 of this agreement. IMECO shall use its best efforts to secure and maintain all such authorizations by governmental regulatory authorities. IMECO shall, to the extent permitted by law, be obligated to perform its duties and obligations hereunder, subject to then applicable provisions of this Section 2.2, (a) whether or not AEGCO shall have received all authorizations of governmental regulatory authorities necessary to permit AEGCO to perform its duties and obligations hereunder, (b) whether or not such authorizations, or any such authorization, shall at any time in question be in effect, and (c) so long as AEGCO and IMECO shall continue to be subsidiary companies of AEP (as said term is defined in Section 2(a)(8) of the 1935 Act) or a successor thereto, whether or not, at any time in question, IMECO shall have performed its duties and obligations under this agreement. In the event that either AEGCO or IMECO shall cease to be such a subsidiary company, then and thereafter IMECO shall not be relieved of its obligation to make payments pursuant to Section 1.3 of this agreement by reason of the failure of AEGCO to perform its duties and obligations hereunder occasioned by Act of God, fire, flood, explosion, strike, civil or military authority, insurrection, riot, act of the elements, failure of equipment, or for any other cause beyond the control of AEGCO; provided that, in any such event, AEGCO shall use its best efforts to put itself in a position where it can perform its duties and obligations hereunder as soon as is reasonably practicable.

3. To the extent that it may legally do so, IMECO and AEGCO each hereby irrevocably waives any defense based on the adequacy of a remedy at law which may be asserted as a bar to the remedy of specific performance in any action brought against it for specific performance of this agreement by IMECO, by AEGCO, or by a trustee under any mortgage or other debt instrument which IMECO or AEGCO may, subject to requisite regulatory authority, enter into, or by any receiver or trustee appointed for IMECO or AEGCO under the bankruptcy or insolvency laws of any jurisdiction to which IMECO or AEGCO is or may be subject; provided, however, that nothing herein contained shall be deemed to constitute a representation or warranty by IMECO or AEGCO that the respective obligations of IMECO or AEGCO under this agreement are, as a matter of law, subject to the equitable remedy of specific performance.

4. IMECO shall not be entitled to set off against any payment required to be made by IMECO under this agreement (i) any amounts owed by AEGCO to IMECO or (ii) the amount of any claim by IMECO against AEGCO. The foregoing, however, shall not affect in any other way the rights and remedies of IMECO with respect to any such amounts owed to IMECO by AEGCO or any such claim by IMECO against AEGCO.

5. The invalidity and unenforceability of any provision of this agreement shall not affect the remaining provisions hereof.

6. This agreement shall become effective forthwith and shall continue until all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged or said Notes have been paid in full, whichever event shall be the later.

7. This agreement shall be binding upon the parties hereto and their successors and assigns, but no assignment hereof, or of any right to any funds due or to become due under this agreement, shall in any event relieve either IMECO or AEGCO of any of their respective obligations hereunder, or, in the case of IMECO, reduce to any extent its entitlement to receive all of the power (and the energy associated therewith) available to AEGCO from time to time at the Rockport Plant.

8. The agreements herein set forth have been made for the benefit of IMECO and AEGCO and their respective successors and assigns, and no other person shall acquire or have any right under or by virtue of this agreement.

9. IMECO and AEGCO may, subject to the provisions of this agreement, enter into a further agreement or agreements between IMECO and AEGCO setting forth detailed terms and provisions relating to the performance by IMECO and AEGCO of their respective obligations under this agreement. No agreement entered into under this Section 9 shall, however, alter to any substantive degree the obligations of either party to this agreement in any manner inconsistent with any of the foregoing sections of this agreement.

10. IMECO shall, at any time and from time to time, be entitled to assign all of its right, title and interest in and to all of the power (and the energy associated therewith) to which IMECO shall be entitled under this agreement, but IMECO shall not, by such assignment, be relieved of any of its obligations and duties under this agreement except through the payment to AEGCO, by or on behalf of IMECO, of the amount or amounts which IMECO shall be obligated to pay pursuant to the terms of this agreement.

IN WITNESS WHEREOF, the parties hereto have caused this agreement to be duly executed as of the day and year first above written.

INDIANA & MICHIGAN ELECTRIC
COMPANY

By G. P. Maloney
Vice President

AEP GENERATING COMPANY

By G. P. Maloney
Vice President

Docket No.: ER89-470-000
Company: AEP
FERC El. Rate Sch. No.: 1
Supp. No.: 6
Filing Date: 5-30-89
Effective Date: I O S

1.6

AMENDMENT NO. 1

TO UNIT POWER AGREEMENT

This Amendment No. 1 dated as of May 8, 1989 by and between Indiana Michigan Power Company ("I&M" or "IMECO", formerly known as Indiana & Michigan Electric Company) and AEP Generating Company ("AEGCO") to the Unit Power Agreement dated as of March 31, 1982 by and between I&M and AEGCO ("Unit Power Agreement"),

WITNESSETH:

WHEREAS, I&M and AEGCO have entered into the Unit Power Agreement whereby, subject to regulatory approvals and certain other conditions, AEGCO agreed to make available, or cause to be made available, to I&M all of the power (and the energy associated therewith) which is available to AEGCO at the Rockport Plant and I&M agreed to pay AEGCO certain amounts;

WHEREAS, AEGCO has entered into six Participation Agreements, dated as of March 15, 1989, whereby it has agreed, subject to regulatory approvals and certain other conditions, to sell its 50% undivided interest in Unit 2 of the Rockport Plant and pursuant to six separate leases (the "Leases"), to leaseback a 50% undivided interest in the unit; and

WHEREAS, Section 3.01 of the Participation Agreements specify that as a condition to closing AEGCO and I&M shall have entered into, and shall have filed with the Federal Energy Regulatory Commission ("FERC") for its approval, an amendment to the Unit Power Agreement which shall, among other things, (i) specifically confirm that basic rent payable under the Leases is an item of operating and other expenses of AEGCO referred to in Section 1.3 thereof, and (ii) specifically provide that the Unit Power Agreement shall continue in full force and effect until the lease term shall have expired or been terminated and all basic rent payable under the Leases shall have been paid in full;

NOW, THEREFORE, in consideration of the terms and agreements hereinafter set forth, the parties hereto agree as follows:

1. Section 1.3 of the Unit Power Agreement is hereby amended to read as follows:

> "1.3 IMECO shall, subject to the provisions and upon compliance with the then applicable requirements of Section 2.2 of this agreement, be entitled to receive all power (and the energy associated therewith) which shall be available to AEGCO at the Rockport Plant, and IMECO agrees to pay to AEGCO in consideration for the right to receive all such power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by IMECO), such amounts from time to time as, when added to amounts received by AEGCO from any other sources, will be at least sufficient to enable AEGCO to pay, when due, all of its operating and other expenses, including provision for the depreciation and/or amortization of the cost of AEGCO's facilities, and lease rental payments, including any amount of Basic Rent (as such term is defined in Section 3(a) of the forms of Lease attached as Exhibit A to the Participation Agreements) which AEGCO may be required to pay pursuant to the Leases, and also including for the purposes of this agreement (i) any amount which AEGCO may be required to pay on account of any interest and/or any commitment fee on all indebtedness for borrowed money issued or assumed by AEGCO (or by any corporation or other entity with which AEGCO shall have merged or consolidated or to which it shall have sold or otherwise disposed of all or substantially all of its assets) and outstanding at the time, and (ii) such additional amounts as are necessary after any required provision for taxes on, or measured by, income to enable AEGCO to pay required dividends on any preferred stock which it may issue and such amount as will represent a return on the common equity of AEGCO equal to the return most recently found in the period of the 24 calendar months immediately preceding the time when payments

are to commence under this Section 1.3 to be fair, and authorized, by the FERC, including any successor Federal regulatory agency as an appropriate return on the common equity of IMECO in a wholesale electric proceeding before FERC under the Federal Power Act, or any legislation enacted in substitution for, or to replace, the Federal Power Act or, if within such period of 24 calendar months immediately preceding the date when payments are to begin under this Section 1.3 no such action by FERC shall have become final and not subject to further proceedings before FERC or a court, the return most recently found to be fair and authorized by the Indiana Utility Regulatory Commission as an appropriate return on the common equity of IMECO in a retail electric proceeding before that Commission. IMECO shall commence the payment of such amounts to AEGCO on the earlier of the following dates: (i) June 30, 1985 and, (ii) the date on which power, including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant."

2. Section 6 of the Unit Power Agreement is hereby amended to read as follows:

"6. This agreement shall become effective forthwith and shall continue in full force and effect until the latter of the date that: (1) all of the Notes issued by AEGCO under the Revolving Credit Agreement, dated as of March 31, 1982, of AEGCO shall have been paid in full, together with all accrued interest thereon; or (ii) the last of the Lease Terms (as that term is defined in the Participation Agreements) shall have expired or been terminated and all Basic Rent payable under all of the Leases shall have been paid in full; provided, however, that in the event that AEGCO shall, prior to such payment, create a Mortgage and Deed of Trust secured by a lien on all, or certain of its fixed physical properties, and shall issue bonds thereunder, this agreement shall continue until said Mortgage and Deed of Trust shall have been satisfied and discharged."

3. This Amendment No. 1 shall become effective on the date on which the last of the following events shall have occurred: (i) this Amendment No. 1 shall have been filed with and accepted for filing without condition or change by the FERC under the Federal Power Act (FPA) as a rate schedule under circumstances where the FERC (a) shall have issued an order under the FPA that

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this Amendment No. 1 shall become effective in its entirety as such rate schedule under the FPA, as proposed by the parties in their filings with the FERC, and (b) shall not have, in such order or any separate order, instituted an investigation or proceeding under the provisions of the FPA with respect to the justness and reasonableness of the provisions of this Amendment No. 1; (ii) the order or orders of the FERC, referred to in (i) above, shall have become final and not subject to review under Section 313 of the FPA; or (iii) the Closings (as defined in the Participation Agreements).

IN WITNESS WHEREOF, the parties hereto have caused this Amendment No. 1 to be duly executed as of the date and year first above written.

INDIANA MICHIGAN POWER COMPANY

By: /s/ R. E. DISBROW
Vice President

AEP GENERATING COMPANY

By: /s/ G. P. MALONEY
Vice President

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RATE DESIGN

The total revenue requirement of AEGCO calculated pursuant to the IMECO-AEGCO Unit Power Agreement designated AEGCO FERC Rate Schedule No. 1 is designed to recover for AEGCO its total cost of providing power (and the energy associated therewith) available to AEGCO at the Rockport Plant.

DETERMINATION OF POWER BILL

In accordance with Section 1.3 of the Unit Power Agreement, I&M agrees to pay AEGCO in consideration for the right to receive all power (and the energy associated therewith) available to AEGCO at the Rockport Plant, as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M), such amounts, less any amounts recovered by AEGCO from other sources, as shall be determined monthly as described below. Such amounts shall be calculated separately for Unit No. 1 (including Common Facilities) and for Unit No. 2. I&M shall then commence the payment of such amounts (power bill) on the earlier of the following dates: (i) June 30, 1985 and (ii) the date on which power including any test power, and any energy associated therewith, shall become available to AEGCO at the Rockport Plant.

The power bill for Unit No. 1 (including Common Facilities) shall be calculated each month and shall reflect recovery only of those costs related to the plant in service. It shall consist of the sum of (a) a return on common equity, (b) a return on other capital, (c) recovery of operating expenses and (d) provision for federal income taxes as described below and as illustrated in the example attached.

(a) Return on Common Equity, which shall be equal to the product of (i) the amount of common equity outstanding at the end of the previous month, but not more than 40% of the capitalization of AEGCO at the end of the previous month; (ii) 1.0133 (12.16% annual rate) as described in Note 1 below; (iii) the Operating Ratio, as defined in Note 2 below; and (iv) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below, plus the product of (v) the amount of common equity in excess of 40% of the capitalization of AEGCO at the end of the previous month, if any such excess shall be determined; (vi) the weighted cost of debt outstanding at the end of the previous month; (vii) the Operating Ratio, as defined in Note 2 below; and (viii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, the amount of common equity shall be equal to the sum of the Common Stock (Accounts 201-203, 209, 210, 212, 214 and 217), Other Paid-In Capital (Accounts 207, 208, 211 and 213), and Retained Earnings (Accounts 215-216) outstanding at the end of the previous month. Total capitalization shall be equal to the sum of Long-term Debt (Accounts 221-226 including current maturities and unamortized debt premium and discounts), Short-Term Debt (Accounts 231 and 233), Preferred Stock (Accounts 204-206), and Common Equity less any Temporary Cash Investments, Special

Deposits and Working Funds (Accounts 132-134, 136, and 145) outstanding at the end of the previous month.

(b) Return on Other Capital, which shall be equal to the product of (i) the amount equal to the net interest expense associated with Long-Term and Short-Term Debt, net of any Temporary Cash Investments, Special Deposits and Working Funds, plus the preferred stock dividend requirement associated with the Preferred Stock outstanding at the end of the previous month; (ii) the Operating Ratio, as defined in Note 2 below; and (iii) the Unit No. 1 Net In-Service Investment Ratio, as defined in Note 3 below.

For the purposes of these calculations, net interest expense shall be equal to the sum of (i) the amount of Long-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Long-Term Debt and (ii) the amount of Short-Term Debt outstanding at the end of the previous month multiplied by the weighted cost of such Short-Term Debt, less (iii) the amount of Temporary Cash Investments, Special Deposits and Working Funds outstanding at the end of the previous month multiplied by the weighted cost of Long Term and Short-Term Debt combined determined pursuant to (i) and (ii) above.

(c) Recovery of Operating Expenses, excluding federal income taxes, which shall consist of provision for depreciation and amortization (Accounts 403-407, 411), including Asset Retirement Obligation (ARO) depreciation and accretion expenses (Accounts 403.1 and 411.10), taxes other than federal income taxes (Accounts 408-411) and operating and maintenance expenses associated with Unit No. 1 (including Common Facilities) offset by other operating revenues as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities (See Note 6). Recovery of expenses for test energy shall be limited to recovery of actual fuel expense as recorded on the Company's books during the month in accordance with the FERC Uniform System of Accounts for Major Electric Utilities. Operating and maintenance expenses shall include, and reflect the recovery of, Steam Power Generation Expenses (Accounts 500-515 including lease rental payments recorded in Account 507), Other Power Supply Expenses (Accounts 555-557), Transmission Expenses (Accounts 560-574), Distribution Expenses (Accounts 580-598), Customer Accounts Expenses (Accounts 901-905), Customer Service and Informational Expenses (Accounts 906-910), Sales Expenses (Accounts 911-917) and Administrative and General Expenses (Accounts 920-933 and 935). Recovery of 501 fuel expenses shall be adjusted to reflect the deferral and/or feedback of unrecovered levelized fuel expenses as may be recorded on the Company's books or as is currently recorded on the books of I&M.

(d) Provision for Unit No. 1's (including Common Facilities) allocated share of net current and deferred federal income tax expense and investment tax credit included in operating income as determined by the Company in accordance with federal income tax law, SEC approved consolidated current tax allocation procedures, and FERC rules and regulations.

For purposes of computing federal income taxes, the interest expense deduction shall be equal to the sum of the net interest expense computed in accordance with paragraph (b) above plus the imputed interest expense associated with common equity that is in excess of 40% of AEGCO's net capitalization.

The power bill for Unit No. 2 shall be calculated in the same manner as described for Unit No. 1 above except that it shall reflect the Unit No. 2 Net In-Service Investment Ratio and those expenses associated with Unit No. 2.

Notes:

1. Return on Equity

The return on common equity allowance shall be based upon a rate of return of 12.16% as set forth in sub-paragraph (a) above.

In October of 1988, and every October thereafter for the effective duration of AEGCO's formula rate, any purchaser under AEGCO's two unit power agreements, any state regulatory commission having jurisdiction over the retail rates of purchasers under these agreements, or any other entity representing customers' interest, may file a complaint with the Commission with respect to the specified rate of return on common equity. If the Commission, in response to such a complaint, or on its own motion, institutes an investigation into the reasonableness of the specified return on common equity, such investigation shall be pursued under the special procedures set forth as follows:

A. The only issue to be addressed under these special procedures shall be the continued collection of the return on equity as incorporated in the formula rate; and

B. Refund will be due, should the return on equity, specified in the formula be found not just and reasonable, dating from the first day of January immediately following the date the complaint is filed or an investigation is instituted by the Commission on its own motion, calculated on the resulting difference in rates due to the application of the return found to be just and reasonable and the return stated in the formula. The first such effective date for the calculation of refunds shall be January 1, 1989.

Any other complaint which challenges the justness and reasonableness of any other component of the filed formula rate or any other complaint filed at any other time which challenges the justness and reasonableness of the specified rate of return on common equity and which is set for investigation by the Commission shall be pursued under Section 206 of the Federal Power Act.

2. Operating Ratio

The Operating Ratio shall be computed each month commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform

System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived by dividing (a) the amount of Electric Plant In Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations); less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111 but excluding amounts associated with Asset Retirement Obligations); plus Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below); Materials and Supplies (Accounts 151-156 and 163 as adjusted pursuant to the provisions of Note 4.C. below); Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below); Prepayments (Account 165); Deferred Ash pond cost (Account 182.3); other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 less Accounts 232-234, 236, 237, 238, 241 and 242); and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No. 2); less Asset Retirement Obligation (Account 230); less Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the plant in service by (b) the sum of (i) the amount determined pursuant to (a) plus (ii) the amount of Construction Work In Progress (Account 707) plus Materials and Supplies (Accounts 151-156 and 163), less Accumulated Deferred Federal Income Taxes related to the construction work in progress plus (iii) Plant Held for Future Use (Account 105), Other Deferred Debits (Account 186) and the amount of fuel inventory over the allowed level (Account 151.10) not otherwise included in (a) above.

3. Net In-Service Investment Ratio

The Unit No. 1 Net In-Service Investment Ratio shall be equal to 1.0 during the period commencing with the month in which Unit No. 1 at the Plant is placed in commercial operation and shall remain at 1.0 up to, but not including, the month in which Unit No. 2 at the Plant is placed in commercial operation. Thereafter, the Net In-Service Investment Ratio shall be computed each month, based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall be derived as follows:

A. Unit No. 1 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 1 and Common Facilities by (b) the sum of the Net In-Service Investment associated with Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

B. Unit No. 2 Net In-Service Investment Ratio shall be derived by dividing (a) the Net In-Service Investment associated with Unit No. 2 by (b) the sum of the Net In-Service Investment associated with the Unit No. 1 and Common Facilities plus the Net In-Service Investment associated with Unit No. 2.

4. Net In-Service Investment

The Net In-Service Investment shall be computed each month commencing with the month in which Unit No. 2 at the Plant is placed in commercial operation. It shall be based on the balances, as recorded on the Company's books in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month and shall consist of the following:

A. Unit No. 1 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), and Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to such Unit No. 1 and Common Facilities in-service investment.

B. Unit No. 2 Net In-Service Investment shall consist of the sum of Electric Plant in Service (Account 101 including amounts associated with leasehold improvements but excluding amounts associated with capitalized leased assets and excluding amounts associated with Asset Retirement Obligations), Plant Held for Future Use (Account 105 pursuant to the provisions of Note 4.D. below), Materials and Supplies (Accounts 151-156 and 163 pursuant to the provisions of Note 4.C. below), Prepayments (Account 165), Deferred Ash pond cost (Account 182.3), Other Deferred Debits (Account 186 pursuant to the provisions of Note 4.D. below), other working capital (Accounts 128, 131, 135, 143, 146, 171 and 174 <u>less</u> Accounts 232-234, 236, 237, 238, 241 and 242), and Unamortized Debt Expense (Account 181), less Other Deferred Credits (Account 253 including the unamortized gain on the sale of Rockport Unit No.2), less Asset Retirement Obligation (Account 230), less Accumulated Provision for Depreciation and Amortization (Accounts 108 and 111), Accumulated Deferred Federal Income Taxes (Accounts 190 and 281-283) and Accumulated Deferred Investment Tax Credit (Account 255) related to the Unit No. 2 in-service investment.

C. AEGCO shall be permitted to earn a return on its fuel inventory, recorded in Account 151.10, not in excess of a 68-day coal supply as defined herein. To the extent AEGCO's actual fuel inventory exceeds the allowable 68-day level, the return on such excess shall be recorded in a memo account. When AEGCO's actual fuel inventory is less than the allowable 68-day level, AEGCO shall be permitted to recover the return previously unrecovered, but in no event shall the power bill reflect a return on fuel inventory in excess of 68-day supply.

A 68-day coal inventory level shall be determined for each unit annually, and shall be based upon the actual experienced daily burn during the preceding calendar year. The actual experienced daily burn shall be defined to exclude the effect of forced and scheduled outages as well as curtailments as follows:

For each unit:

$$\text{Actual experienced daily burn} = 24 \text{ hours} \left(\frac{\text{Tons burned per year}}{\text{Operating hours}} \right)$$

Where:

Operating hours = Hours in year minus forced and scheduled outage hours minus curtailment equivalent outage hours

and

Curtailment equivalent outage hours = The product for each curtailment of:

$$\frac{\text{kW of curtailed capacity}}{\text{kW of rated capacity}} \quad x \quad \text{Curtailment hours}$$

The value of the allowable 68-day coal supply used to determine each month's power bill shall be equal to the number of tons determined above multiplied by the cost per ton of coal in inventory at the end of the previous month.

For 1990, a 68-day coal supply for AEGCO's share of Rockport Unit No. 2 shall be based on 12 months ending December 1990 data. For 1990 billing purposes, however, a 68-day coal supply for AEGCO's share of Rockport Unit No.2 shall initially be assumed to be equal to the 68-day coal supply for AEGCO's share of Rockport Unit No. 1, adjusted to reflect the Btu content and the unit cost of the coal for Rockport Unit No. 2.

AEGCO shall maintain a cumulative record of the unrecovered return as well as the subsequent recovery of that return as follows:

i) To the extent that AEGCO's actual fuel inventory exceeds the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the sum of the unrecovered return on fuel inventory and the return on previously unrecovered amounts. The unrecovered return on fuel inventory shall be calculated each month by deriving the difference between the power bill that would result if full recovery were provided and the power bill that results with the 68-day limitation imposed. The return on previously unrecovered amounts shall be calculated by multiplying the cumulative return unrecovered at the end of the previous month by the capital costs used to derive the power bill, adjusted for federal income taxes.

ii) To the extent that AEGCO's fuel inventory is less than the allowable 68-day coal supply, AEGCO shall record each month an amount equal to the return on previously unrecovered amounts less the recovered return in excess of actual inventory levels. The return on previously unrecovered amounts shall be calculated as described in (i) above. The recovered return in excess of actual inventory levels shall be calculated by deriving the difference between the power bill that would result if actual inventory balances were used and the power bill that results with an imputed inventory level. In no event will the cumulative value of the unrecovered return be allowed to fall below zero.

D. AEGCO shall be permitted to include as part of its Net In-Service Investment Numerator amounts subsequently recorded in Accounts 105 and 186 subject to the conditions set forth in the Offer of Settlement in FERC Docket No. ER84-579-000, et al.

E. Other Special Funds (Account 128), Other Current and Accrued Assets (Accounts 131, 135, 143, 146, 171 and 174), Other Deferred Debits (Account 181), Other Current and Accrued Liabilities (Accounts 232-234, 236, 237, 238, 241 and 242), and Other Deferred Credits (Account 253) shall be directly assigned to unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such balances shall be allocated between the units in proportion to the net dependable capability of each of the units.

F. To recognize that the lease rental expense will be collected monthly but that the lease payment will be paid semiannually, the lease rental payable balance will be reflected as a rate base reduction in calculating the operating ratio and the Unit 2 net-in-service investment ratio as a means to credit the Unit 2 customers for the time value of money.

5. Investment Balances

For the purpose of calculating the Operating Ratio and Net In-Service Investment Ratio, amounts shall reflect the balances, as recorded on the Company's book in accordance with the FERC Uniform System of Accounts for Major Electric Utilities, outstanding at the end of the previous month, except that when plant greater than or equal to 1% of the prior month ending plant value is transferred into service during the current month, such prior month balances shall be adjusted to reflect such transfers to service. Such adjustment shall be pro-rated for the number of days during the month that such plant addition was in-service.

6. Allocation of Expenses

Operating expenses shall be directly assigned to Unit No. 1 (including Common Facilities) or Unit No. 2 whenever possible. Whenever such direct assignment is not practical, such expenses shall be allocated between the units in accordance with the basis that gave rise to such expense.

AEGCO's operating and maintenance expenses shall include, and AEGCO shall be allowed recovery of, administrative and general expenses, related payroll taxes and other cost, allocated to AEGCO by I&M as operator of the Rockport Plant or incurred directly by AEGCO.

I&M shall allocate to AEGCO, a portion of I&M's administrative and general expenses charged to Accounts 920, 921, 922, 923, 924, 925, 926, 931 and 935; related payroll taxes charge to Account 408; and a portion of the expenses of the Rockport Information Center charged to Accounts 506, 511 and 514 that generally relate to Rockport Plant operations. Such charges shall be allocated to AEGCO on the basis of the ratio of AEGCO's share of the Rockport Plant operation and maintenance wages and salaries, divided by the sum of total Rockport Plant operations and maintenance wages and salaries, plus all other I&M operation and maintenance wages and salaries, less I&M's administrative and general wages and salaries. For the period beginning December 10, 1984 and ending December 31, 1985 this ratio will be developed based on actual 1985 amounts. In subsequent calendar years, this ratio will be adjusted annually based on the prior calendar year's amounts.

AEGCO's operation and maintenance expenses shall also include, and AEGCO shall be allowed recovery of, other administrative and general expenses directly incurred by AEGCO and included in the appropriate administrative and general expense accounts.

BILLINGS AND PAYMENTS

All bills for amounts owing hereunder shall be due and payable on the fifteenth day of the month next following the month or other period to which such bills are applicable, or on the tenth day following receipt of the bill, whichever date is later. Interest on unpaid amounts shall accrue daily at the prime interest rate per annum in effect on the due date at the

Citibank, plus 2% per annum, from the due date until the date upon which payment is made. Unless otherwise agreed upon, the calendar month shall be the standard period for the purpose of settlements under this Agreement. If bills cannot be accurately determined at any time, they shall be rendered on an estimated basis and subsequently adjusted to conform to the terms of the unit power agreements.

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 2
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

DATA REQUEST NO. 2-29-AG

Request

Refer to AG 1-11 attachment 1:

a. Has the Michigan Public Service Commission ever approved this agreement? If yes, identify the case number and order date.

b. Referring to section 1.3 of the agreement, how was the return on equity calculated?

c. Referring to section 1.3 of the agreement, provide the amounts received by AEG from any other sources in 2020, and explain how those amounts were used to calculate the amount I&M owed.

d. Identify all actions I&M has taken since the Commission's June 7, 2019 Order in Case No. U-18404 to seek or pursue amendments, new contractual arrangements, or other negotiations regarding any aspect of this agreement, including but not limited to the return on equity.

e. Produce all documents and communications related to your response to the preceding sub-part.

Response

a. The Commission originally approved the inclusion of the capacity charges related to the purchase of Rockport Plant Unit 2 capacity from AEP Generating Company (AEG) in its order in Case No. U-9656, dated Feb. 12, 1991. Furthermore, the costs of the Unit Power Agreement with AEG have been included in all subsequent base rate cases and power supply cost recovery cases since that date.

b. The calculation for the return on equity component of the bill is based on the method identified in AEP Generating Company Rate Schedule No. 1, on file with the FERC.

c. I&M objects to this request on the basis that it seeks information that is outside the scope of the PSCR and, therefore, is not reasonably calculated to lead to the discovery of relevant or admissible evidence. In support of this objection, the Company states that any amounts received by AEG other than those costs included in the Company's 2020 PSCR Reconciliation filing are not relevant in determining the reasonableness of the costs included in this reconciliation proceeding.

d. Please see FERC Docket no. ER19-717-000 for the most recent rate update filing made on behalf of AEP Generating Company to update their formula rate calculation.

e. The docket and all pertinent documents can be found at FERC.gov.

INDIANA MICHIGAN POWER COMPANY
ATTORNEY GENERAL OF MICHIGAN
DATA REQUEST SET NO. 2
CASE NO. U-20530 (2020 PSCR RECONCILIATION)

SUPPLEMENTAL RESPONSE

c. I&M objects to the extent this question seeks information that is confidential and proprietary. Without waiving this objection, the confidential information will be provided pursuant to the protective order issued May 24, 2021 in this docket. Please see the following AEG Power Bills:

- AG 2-29 CONFIDENTIAL 01_January_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 02_February_2020_Actual.xls
- AG 2-29 CONFIDENTIAL 03_March_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 04_April_2020_Estimation.xls
- AG 2-29 CONFIDENTIAL 05_May_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 06_June_2020_ESTIMATE.xls
- AG 2-29 CONFIDENTIAL 07_July_2020_ESTIMATE.xls
- AG 2-29 CONFIDENTIAL 08_August_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 09_September_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 10_October_2020_Estimate.xls
- AG 2-29 CONFIDENTIAL 11_November_2020_Estimated Version 2.xls
- AG 2-29 CONFIDENTIAL 12_December_2020_Estimation.xls

As to objection
Counsel

Preparer
Stegall

9656
2-12-91

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **INDIANA MICHIGAN POWER COMPANY** for authority to increase its rates for the sale of electric energy.	)	Case No. U-9656

At the February 12, 1991 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Steven M. Fetter, Chairman
Hon. William E. Long, Commissioner
Hon. Ronald E. Russell, Commissioner

ORDER APPROVING SETTLEMENT AGREEMENT

On June 18, 1990, Indiana Michigan Power Company (I&M) filed an application, with supporting testimony and proposed exhibits, requesting authority to increase its retail electric rates by an annual amount of approximately $15,821,000 and to make certain changes to the design of its tariffs and to its terms and conditions of service.

Pursuant to due notice, a prehearing conference was held on August 3, 1990 before Administrative Law Judge Theodora M. Mace, substituting for Adminstrative Law Judge Robert L. Shankland. I&M, the Commission Staff (Staff), the Association of Businesses Advocating Tariff Equity (ABATE), and Whirlpool Corporation and Southern Michigan Cold Storage Company (Whirlpool/Southern Michigan) participated in the proceedings.

In November and December 1990 and January 1991, the Staff, ABATE, Whirlpool/ Southern Michigan, and I&M engaged in settlement discussions. The parties reached an agreement, and a settlement agreement signed by all parties, a copy of which is attached as Appendix A, was submitted.

The settlement agreement provides, among other things, that I&M's Michigan jurisdictional retail electric revenues should be increased by $10,400,000 annually, to be made effective in two steps. The amount of the Step One increase is $7,400,000, which is proposed to be effective for service rendered on and after April 1, 1991. The amount of the Step Two increase is $3,000,000, which is proposed to be effective for service rendered on and after April 1, 1992. The Step Two increase includes an increase of $1,325,000 to the annual Michigan jurisdictional provision for decommissioning I&M's Donald C. Cook Nuclear Plant. Exhibits A and B to the settlement agreement are the tariff sheets reflecting the Step One and Step Two increases, respectively.

Both Rule 33 of the Commission's Rules of Practice and Procedure, R 460.43, and Section 78 of the Administrative Procedures Act of 1969, MCL 24.278, provide for the disposition of matters by stipulation and agreement. Those provisions do not relieve the Commission of its responsibility to determine whether the stipulation of the parties is in the public interest.

After a review of the settlement agreement in this case, we find it is reasonable and in the public interest and should be approved.

Although the process of settlement involves compromise, the Commission views it as an opportunity for parties to resolve their disputes fairly and expeditiously. A solution devised by the parties themselves is more likely to fit their needs and circumstances. A settlement also conserves the scarce resources of the parties and the Commission. For these reasons, and as long as it can be demonstrated that the public interest is served by a particular settlement, the Commission encourages parties to settle their disputes.

The Commission finds that:

a. Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, 1979 Administrative Code, R 460.11 et seq.

b. The settlement agreement is reasonable and in the public interest, and should be approved in its entirety.

c. I&M should be authorized to increase its rates for the sale of electricity in two steps, as provided in the settlement agreement.

d. I&M should be authorized to change its power supply cost recovery basing point and adjust its power supply cost recovery factor, as provided in the settlement agreement.

e. The capacity charges related to the purchase of Rockport Plant Unit No. 2 capacity by I&M from AEP Generating Company should be approved for the purposes of MCL 460.6j(13)(b), as provided in the settlement agreement.

f. The proposed language satisfying the disclosure requirements for nuclear decommissioning expense set forth in Exhibit C to the settlement agreement is reasonable and should be incorporated into this order by reference.

THEREFORE, IT IS ORDERED that:

A. The settlement agreement attached as Appendix A, is approved in its entirety. Due to their length, the exhibits to the settlement agreement, which are contained in the official docket, are made part of this order by reference.

B. Indiana Michigan Power Company is authorized to increase its rates by $10,400,000 annually for the sale of electricity as described in the settlement agreement, without further order of the Commission.

C. Indiana Michigan Power Company shall file, within 30 days of the effective dates of the Step One and Step Two increases, respectively, tariff sheets in substantial compliance with those referenced as Exhibits A and B to the settlement agreement.

D. Indiana Michigan Power Company is authorized to change its power supply cost recovery basing point and adjust its power supply cost recovery factor, as provided in the settlement agreement.

E. The capacity charges related to the purchase of Rockport Plant Unit No. 2 capacity by Indiana Michigan Power Company from AEP Generating Company are approved for purposes of MCL 460.6j(13)(b), as provided in the settlement agreement.

F. The language addressing the disclosure requirements for nuclear decommissioning expense set forth in Exhibit C to the settlement agreement is incorporated into this order by reference.

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

/s/ Steven M. Fetter
Chairman

(S E A L)

/s/ William E. Long
Commissioner

/s/ Ronald E. Russell
Commissioner

By its action of February 12, 1991.

/s/ Dorothy Wideman
Its Executive Secretary

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the Matter of the Application of INDIANA MICHIGAN POWER COMPANY for Authority to Increase its Rates for the Sale of Electric Energy.	Case No. U-9656

SETTLEMENT AGREEMENT

For the purpose of settling the issues in the above captioned proceeding only, and subject to the acceptance and approval of the Michigan Public Service Commission (Commission) without modification, and without prejudice to the pre-negotiation positions of the parties in this or any other proceeding, the parties hereto agree and stipulate as follows:

On June 18, 1990, Indiana Michigan Power Company (I&M) filed its Application, together with the prepared testimony and proposed exhibits of its witnesses in support of the Application, requesting authority to amend its electric rate schedules to increase jurisdictional operating revenues by approximately $15,821,000 annually. I&M's Application, testimony and exhibits also proposed certain changes to the design of its electric tariffs and to its Terms and Conditions of Service, including a reduction of the Power Supply Cost Recovery (PSCR) basing point.

Pursuant to the Commission's Notice of Hearing dated June 28, 1990, I&M gave notice to its customers by publishing a Notice of Hearing in its Michigan electric service area, as well as by serving a copy of the Commission's Notice of Hearing upon all cities, incorporated villages, townships and counties within I&M's Michigan electric service area and upon all Intervenors who appeared in Case Nos. U-7791 and U-9458 (I&M's last base rate case and 1990 PSCR Plan case). I&M's Proof of Service and Affidavits of Publication were filed with the Commission on August 3, 1990.

Pursuant to the Notice of Hearing, a prehearing conference was held on August 3, 1990, at the Commission's offices in Lansing, Michigan, before Administrative Law Judge (ALJ) Theodora M. Mace, who was substituting for ALJ Robert Shankland. At that prehearing conference, the Petitions to Intervene of the Association of Businesses Advocating Tariff Equity (ABATE) and of Whirlpool Corporation and Southern Michigan Cold Storage Company (Whirlpool/Southern Michigan) were granted. In addition, the Commission Staff (Staff) appeared.

The Staff conducted an audit of I&M's books and records, the parties engaged in discovery, and settlement discussions took place among the parties in November and December, 1990 and January, 1991.

Encouraged by the Commission's Rules of Practice and Procedure (Rule 33; 1979 AC, R 460.43), I&M, Staff, Whirlpool/Southern Michigan and ABATE have resolved, through settlement negotiations, the contested issues in this proceeding as set forth in this Settlement Agreement.

It is the opinion of the parties hereto that this Settlement Agreement will promote the public interest, will aid the expeditious conclusion of this case, and will minimize the time and expense which would otherwise have to be devoted to this matter by the Commission and all of the parties. This Settlement Agreement is for the sole purpose of resolving this case and all provisions of the same are dependent upon all other provisions contained herein.

In addition to the foregoing, the parties specifically agree as follows:

1. Based upon a projected test year ending December 31, 1991, I&M has a revenue deficiency from its Michigan jurisdictional retail sales of electric energy in the annual amount of $10,400,000, which includes an

increase in the provision for nuclear decommissioning of $1,325,000. The parties agree to the jurisdictional retail revenue deficiency of $10,400,000, but not necessarily to the individual components or amounts which may have been considered in the determination of that deficiency, except for those components or amounts specifically set forth in this Settlement Agreement.

2. A cost rate for I&M's common equity of 13.00% has been used in arriving at the revenue deficiency in Paragraph 1. The Staff used this rate to determine an overall rate of return for I&M of 9.46%. By this Settlement Agreement, the parties only agree to the cost rate for common equity.

3. I&M's jurisdictional retail electric rates should be revised as shown on Exhibits A and B attached hereto to increase I&M's revenues by the amount of the annual revenue deficiency in two steps (Step One and Step Two). The Step One increase in the amount of $7,400,000, should be made effective for service rendered on and after April 1, 1991 (Exhibit A). The Step Two increase, in the amount of $3,000,000, should be made effective for service rendered on and after April 1, 1992 (Exhibit B).

4. The total annual Michigan jurisdictional provision for decommissioning the Donald C. Cook Nuclear Plant should be $2,363,000, which is an increase of $1,325,000 over the current annual jurisdictional provision. It is further agreed that the Commission's final order in this proceeding should incorporate language proposed by I&M to satisfy the disclosure requirements of the Internal Revenue Service (IRS), which is set forth in Exhibit C attached hereto. The parties agree that the increase in the annual jurisdictional provision for nuclear decommissioning should be made effective on April 1, 1992, as part of the $3,000,000 Step Two

increase. It is agreed that the annual jurisdictional provision will continue to be collected as a separate surcharge on the base rates charged to customers, determined using the methodology approved by the Commission in Case No. U-8559, and that the current separate surcharge will continue in effect until increased as a part of the Step Two increase.

5. I&M agrees that it will not file a rate application requesting an increase in its base retail electric rates before July 1, 1992. This filing moratorium shall also apply, for the same period, to applications requesting other non-PSCR related rate increases, including increases in the nuclear decommissioning surcharge, except for limited purpose proceedings addressing: (i) energy conservation surcharges, (ii) the effect on rates of federal or state tax law changes affecting I&M's annual jurisdictional revenue requirement by $1,000,000 or more, or (iii) implementation of the DSS Positive Billing Program or similar government mandated programs.

6. I&M agrees that it will not propose to make tariffs effective which increase the number of on-peak hours from the number incorporated in the present case prior to April 1, 1994.

7. The determination of the revenue deficiency specified in this Settlement Agreement incorporates the effects of the revised depreciation accrual rates for I&M approved in Case Nos. U-9231 and U-9591.

8. The determination of the revenue deficiency specified in this Settlement Agreement does not include the recovery of any costs associated with I&M's Energy Conservation Services (ECS) Program.

9. Pursuant to the Commission's Opinion and Order dated November 21, 1990 in I&M's 1990 PSCR Plan case (Case No. U-9458), the parties have considered all of the effects on I&M's cost of service of the addition of

Rockport Plant Unit No. 2 (Rockport 2) to I&M's available generating capacity. Based on the evaluation of all of the cost-of-service effects, including capacity settlement effects, the parties agree that I&M's Michigan ratepayers are being fairly compensated for I&M's contribution of generating capacity to the AEP System, including Rockport 2. In recognition of this, effective April 1, 1991, the costs associated with I&M's leased share of Rockport 2 are included in calculating the total revenue deficiency agreed upon in this Settlement Agreement. Notwithstanding the revenue deficiency agreed to in this Settlement Agreement, any party may challenge the inclusion of I&M's leased share of Rockport 2 costs in the rates charged to I&M's Michigan customers in a future general rate case or other appropriate proceeding.

10. In recognition of the fact that I&M's Michigan ratepayers are being fairly compensated for the costs of the purchase of Rockport 2 capacity by I&M from AEP Generating Company (AEG), the parties agree that the capacity charges associated with the purchase of Rockport 2 capacity by I&M from AEG should be approved for purposes of MCL 460.6j(13)(b); MSA 22.13(6j)(13)(b). The parties explicitly recognize that any party may challenge the inclusion of capacity charges associated with the purchase of Rockport 2 capacity by I&M from AEG in rates charged to Michigan ratepayers in a future PSCR proceeding if circumstances change such that Michigan ratepayers are no longer fairly compensated for the cost of the generating capacity which I&M makes available to the AEP System. In any future proceeding, nothing herein shall be construed as an agreement by I&M nor any other party as to the validity of such a challenge, the extent of Commission jurisdiction with

respect to Rockport 2 costs or the appropriate standard for determining the recoverability of such costs.

11. The PSCR-related effects of Rockport 2, including the capacity charges related to the purchase of Rockport 2 capacity by I&M from AEG, and all of the capacity settlement effects of Rockport 2, should be reflected in I&M's PSCR factor on and after the effective date of the Step One increase. The annual PSCR-related effects of Rockport 2 are estimated on Exhibit D attached hereto. It is further agreed that I&M's power supply cost basing point shall be changed from 9.62 mills per kwh to 3.33 mills per kwh and I&M shall adjust for billing purposes its PSCR factor to reflect such change in the PSCR cost basing point. Both the change in the power supply cost basing point and the adjustment to the PSCR factor shall become effective for service rendered on and after the effective date of the Step One increase. I&M will use its best efforts to adjust its 1991 PSCR factor to insure that there is no underrecovery of PSCR revenues in 1991 caused solely by the exclusion of Rockport 2 effects from January 1, 1991 to the effective date of the Step 1 increase pursuant to this Settlement Agreement. The parties agree that PSCR costs for each month from January 1, 1991 to the effective date of the Step 1 increase will be calculated so that the PSCR-related effects of Rockport 2 are excluded in the same manner that they were excluded by the Commission's order in Case No. U-9458.

12. The PSCR-related effects of Rockport 2 should not be included in I&M's 1990 PSCR reconciliation. The parties agree that the calculation of the PSCR-related effects of Rockport 2 shall be made consistent with the methodology used in the Commission's order in Case No. U-9458. The parties further agree that if I&M experiences an underrecovery in its power supply

costs for 1990 greater than $500,000, I&M will propose in its Application for a 1990 PSCR reconciliation that the requested surcharge be collected from I&M's Michigan ratepayers over a period of not less than six (6) months.

13. The rates incorporated in the revised tariff sheets included in Exhibits A and B are intended to provide I&M with a total annual jurisdictional revenue increase of $10,400,000 to be made effective in two steps as described in Paragraphs 3 and 4. The revenue calculations reflecting current and proposed rates are shown on Exhibit D attached hereto. The parties recommend that the Commission approve the revised tariff sheets attached as Exhibits A and B.

14. I&M will file, within six (6) months of the date of a final order approving this Settlement Agreement, an application with the Commission requesting all requisite approvals related to a merger of Michigan Power Company (MPCo), an operating company affiliate of I&M, into I&M. The parties to this Settlement Agreement agree to not oppose the following requests by I&M in such application which are conditions precedent to the merger of MPCo into I&M:

a. The initial establishment of two rate zones, using then-existing base rates, in the service territory of the merged entity, one for MPCo's current service territory and one for I&M's current service territory.

b. The continued recovery in the rates of the MPCo rate zone of all costs deferred as a result of the phasing into rates of Rockport Plant Unit No. 1 (Rockport 1), as ordered by the Federal Energy Regulation Commission in Docket Nos. ER84-587-000 and ER88-30-000, until all such costs are fully amortized.

c. Authority for I&M to continue related accounting to recognize the phase-in of Rockport 1 with respect to the MPCo rate zone.

The parties recognize that the merger of MPCo into I&M can be consummated only after all appropriate federal and state regulation approvals have been granted, which I&M agrees to promptly seek.

15. This Settlement Agreement is intended for final disposition of this proceeding, and the parties hereto join in respectfully requesting the Commission to grant prompt approval of the same. The Staff certifies that this Settlement Agreement is reasonable and in the public interest. Each party agrees not to appeal, challenge or contest the approvals granted by the Commission in this case if they are the result of an order of the Commission in this proceeding, accepting and approving this Settlement Agreement without modification. If the Commission does not accept the Settlement Agreement without modification, the Settlement Agreement shall be withdrawn and shall not constitute any part of the record in this proceeding or be used for any other purposes whatsoever.

16. This Settlement Agreement has been made for the sole and express purpose of reaching a compromise among the positions of the parties to this proceeding. All offers of settlement and discussion relating thereto are and shall be privileged. The Settlement Agreement and the Commission order approving same shall not be used as precedent or in any other manner, nor be admissible, for any other purpose in connection with this proceeding or any other judicial or administrative proceeding, except for the purpose of enforcing this Settlement Agreement.

17. The parties join in requesting that the Commission act expeditiously in evaluating this Settlement Agreement and issuing a final order so that the Step One increase agreed to herein can become effective on April 1, 1991.

18. The parties hereto agree to waive Section 81 of the Administrative Procedures Act of 1969 (MCL 24.281; MSA 3.560(181)).

Dated: Jan 18, 1991

INDIANA MICHIGAN POWER COMPANY

By

Daniel J. Demlow (P-12666)
Honigman Miller Schwartz and Cohn
Its Attorneys

Dated: Jan 18, 1991

MICHIGAN PUBLIC SERVICE COMMISSION

By Tonatzin M Alfaro Garcia

Philip J. Rosewarne (P-19651)
Tonatzin M. Alfaro Garcia (P-36542)
Assistant Attorneys General
Attorney for Staff

Dated: 18 January, 1991

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

By Nancy L. Lukey

Nancy L. Lukey (P-28954)
Hill Lewis
Its Attorneys

Dated: Jan 24, 1991

WHIRLPOOL CORPORATION AND SOUTHERN MICHIGAN COLD STORAGE COMPANY

By

Albert Ernst (P-24059)
Dykema Gossett
Its Attorneys

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Case No. U-9656
Exhibit D to
Settlement Agreement

INDIANA MICHIGAN POWER COMPANY
SUMMARY OF ESTIMATED REVENUE -
PRESENT AND PROPOSED RATES

Rate Class	Revenue Present Rates	Revenue Proposed Rates Step One	Step One Dollar Increase	Step One Percentage Increase	Revenue Proposed Rates Step Two	Step Two Dollar Increase	Step Two Percentage Increase
Residential	$37,794,324	$41,089,989	$3,295,665	8.72%	$42,425,414	$1,335,425	3.25%
Commercial	24,781,483	26,941,121	2,159,638	8.72%	27,817,534	876,413	3.25%
Industrial	19,306,147	20,989,643	1,683,496	8.72%	21,671,806	682,163	3.25%
Governmental	2,997,236	3,258,437	261,201	8.72%	3,364,436	105,999	3.25%
Sub-Total	84,879,190	92,279,190	7,400,000	8.72%	95,279,190	3,000,000	3.25%
Estimated PSCR Related Effect*	4,007,796		(4,007,796)	--	--	--	--
Total	$88,886,986	$92,279,190	3,392,204	3.82%	$95,279,190	$3,000,000	3.25%

*This represents the estimated net PSCR effect of Rockport 2, as calculated by I&M pursuant to the November 21, 1990 Opinion and Order in Case No. U-9458. The parties recognize that this is an estimate only and they are not bound by the specific dollar amount shown.

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Table 5-17 Capacity market clearing prices: 2007/2008 through 2021/2022 RPM Auctions

		RPM Clearing Price ($ per MW-day)												
	Product Type	RTO	MAAC	APS	PPL	EMAAC	SWMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE
2019/2020 BRA	Base Capacity	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$80.00	$80.00	$182.77	$80.30
2019/2020 BRA	Base Capacity DR/EE	$80.00	$80.00	$80.00	$80.00	$99.77	$80.00	$99.77	$99.77	$99.77	$0.01	$80.00	$182.77	$80.30
2019/2020 BRA	Capacity Performance	$100.00	$100.00	$100.00	$100.00	$119.77	$100.00	$119.77	$119.77	$119.77	$100.00	$100.00	$202.77	$100.30
2019/2020 First Incremental Auction	Base Capacity	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Base Capacity DR/EE	$15.00	$15.00	$15.00	$15.00	$22.22	$15.00	$22.22	$22.22	$22.22	$15.00	$15.00	$15.00	$15.00
2019/2020 First Incremental Auction	Capacity Performance	$51.33	$51.33	$51.33	$51.33	$58.55	$51.33	$58.55	$58.55	$58.55	$51.33	$51.33	$51.33	$51.33
2019/2020 Second Incremental Auction	Base Capacity	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Base Capacity DR/EE	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$10.01	$32.14
2019/2020 Second Incremental Auction	Capacity Performance	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$32.87	$55.00
2019/2020 Third Incremental Auction	Base Capacity	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Base Capacity DR/EE	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$21.35	$20.00	$21.35	$21.35	$21.35
2019/2020 Third Incremental Auction	Capacity Performance	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35	$28.35
2020/2021 BRA	Capacity Performance	$76.53	$86.04	$76.53	$86.04	$187.87	$86.04	$187.87	$187.87	$187.87	$86.04	$76.53	$188.12	$86.04
2020/2021 First Incremental Auction	Capacity Performance	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90	$42.90
2020/2021 Second Incremental Auction	Capacity Performance	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25	$20.25
2020/2021 Third Incremental Auction	Capacity Performance	$10.00	$15.25	$10.00	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$15.25	$10.00	$10.00	$15.25
2021/2022 BRA	Capacity Performance	$140.00	$140.00	$140.00	$140.00	$165.73	$140.00	$165.73	$204.29	$204.29	$140.00	$171.33	$195.55	$200.30
2021/2022 First Incremental Auction	Capacity Performance	$23.00	$23.00	$23.00	$23.00	$25.00	$23.00	$25.00	$45.00	$219.00	$23.00	$23.00	$23.00	$60.00
2021/2022 Second Incremental Auction	Capacity Performance	$10.26	$10.26	$10.26	$10.26	$15.37	$10.26	$15.37	$125.00	$125.00	$10.26	$10.26	$10.26	$70.00

Table 5-18 Capacity market cleared MW: 2007/2008 through 2021/2022 RPM Auctions[105]

		UCAP (MW)												
Delivery Year	Auction	RTO	MAAC	APS	PPL	EMAAC	DPL South	PSEG	PSEG North	Pepco	ATSI	ComEd	BGE	TOTAL
2019/2020	BASE	60,061.8	9,996.2	9,066.6	12,754.9	20,382.4	1,598.5	5,583.1	3,228.9	6,971.7	10,291.1	22,971.4	4,422.9	167,329.5
2019/2020	FIRST	784.5	249.4	39.3	157.7	78.7	11.7	10.6	28.8	43.6	147.5	711.4	31.9	2,295.1
2019/2020	SECOND	442.9	160.4	30.1	146.2	210.1	21.2	38.1	44.8	41.9	263.6	105.8	107.5	1,612.6
2019/2020	THIRD	1,608.0	440.9	429.4	1,216.6	265.7	2.4	180.4	23.2	83.6	454.2	867.4	255.2	5,827.0
2020/2021	BASE	56,012.4	11,413.2	8,990.6	14,398.2	19,978.5	1,647.2	5,041.2	2,975.4	6,410.0	9,925.9	23,960.3	4,021.1	164,773.9
2020/2021	FIRST	1,265.6	331.0	144.2	83.4	76.2	38.9	105.8	32.0	97.8	666.9	644.4	38.7	3,524.8
2020/2021	SECOND	447.2	206.9	53.0	30.7	302.9	28.4	29.5	48.8	35.4	366.2	194.6	160.3	1,903.8
2020/2021	THIRD	1,106.6	569.7	118.7	89.0	194.1	33.1	423.0	137.0	93.1	554.3	127.7	39.8	3,486.0
2021/2022	BASE	55,642.6	12,565.1	10,136.1	15,368.6	19,857.3	1,673.8	4,667.2	3,134.1	6,546.1	8,010.5	22,358.1	3,667.8	163,627.3
2021/2022	FIRST	281.7	200.4	45.9	27.2	119.0	15.3	18.3	79.1	207.9	739.3	360.4	48.7	2,143.2
2021/2022	SECOND	1,307.8	335.8	30.3	55.4	129.9	39.3	97.0	98.1	75.7	1,216.8	205.9	115.5	3,707.5

105 The MW values in this table refer to rest of LDA or RTO values, which are net of nested LDA values.

Table 5-19 Weighted average clearing prices by zone: 2018/2019 through 2021/2022

	Weighted Average Clearing Price ($ per MW-day)			
LDA	2018/2019	2019/2020	2020/2021	2021/2022
RTO				
AEP	$158.20	$93.63	$74.42	$137.02
APS	$158.20	$93.63	$74.42	$137.02
ATSI	$148.42	$92.97	$69.75	$149.70
Cleveland	$158.68	$89.17	$68.93	$106.96
ComEd	$199.02	$188.90	$182.15	$191.17
DAY	$158.20	$93.63	$72.42	$138.19
DEOK	$158.20	$93.63	$121.24	$133.54
DLCO	$158.20	$93.63	$74.42	$137.02
Dominion	$158.20	$93.63	$74.42	$137.02
EKPC	$158.20	$93.63	$74.42	$137.02
MAAC				
EMAAC				
AECO	$214.31	$112.48	$182.04	$164.07
DPL	$214.31	$112.48	$182.04	$164.07
DPL South	$211.38	$115.95	$178.65	$161.07
JCPL	$214.31	$112.48	$182.04	$164.07
PECO	$214.31	$112.48	$182.04	$164.07
PSEG	$210.92	$110.56	$165.74	$199.70
PSEG North	$211.71	$116.03	$176.45	$202.27
RECO	$214.31	$112.48	$182.04	$164.07
SWMAAC				
BGE	$141.58	$88.20	$80.71	$189.98
Pepco	$144.90	$90.59	$84.24	$134.58
WMAAC				
Met-Ed	$152.65	$93.81	$81.85	$136.11
PENELEC	$152.65	$93.81	$81.85	$136.11
PPL	$147.90	$88.53	$85.07	$139.16

Table 5-20 RPM revenue by delivery year: 2007/2008 through 2021/2022[106]

Delivery Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Days	RPM Revenue
2007/2008	$89.78	129,409.2	366	$4,252,287,381
2008/2009	$127.67	130,629.8	365	$6,087,147,586
2009/2010	$153.37	134,030.2	365	$7,503,218,157
2010/2011	$172.71	134,036.2	365	$8,449,652,496
2011/2012	$108.63	134,182.6	366	$5,335,087,023
2012/2013	$75.08	141,283.9	365	$3,871,714,635
2013/2014	$116.55	159,844.5	365	$6,799,778,047
2014/2015	$126.40	161,205.0	365	$7,437,267,646
2015/2016	$160.01	173,519.4	366	$10,161,726,902
2016/2017	$121.84	179,749.0	365	$7,993,888,695
2017/2018	$141.19	180,590.5	365	$9,306,676,719
2018/2019	$172.09	175,996.0	365	$11,054,943,851
2019/2020	$109.82	177,064.2	366	$7,116,815,360
2020/2021	$111.07	173,688.5	365	$7,041,524,517
2021/2022	$151.15	169,478.0	365	$9,349,894,658

Table 5-21 RPM revenue by calendar year: 2007 through 2022[107]

Year	Weighted Average RPM Price ($ per MW-day)	Weighted Average Cleared UCAP (MW)	Effective Days	RPM Revenue
2007	$89.78	75,665.5	214	$2,486,310,108
2008	$111.93	130,332.1	366	$5,334,880,241
2009	$142.74	132,623.5	365	$6,917,391,702
2010	$164.71	134,033.7	365	$8,058,113,907
2011	$135.14	133,907.1	365	$6,615,032,130
2012	$89.01	138,561.1	366	$4,485,656,150
2013	$99.39	152,166.0	365	$5,588,442,225
2014	$122.32	160,642.2	365	$7,173,539,072
2015	$146.10	168,147.0	365	$9,018,343,604
2016	$137.69	177,449.8	366	$8,906,998,628
2017	$133.19	180,242.4	365	$8,763,578,112
2018	$159.31	177,896.7	365	$10,331,688,133
2019	$135.58	176,338.6	365	$8,734,613,179
2020	$110.55	175,368.7	366	$7,084,072,778
2021	$134.57	171,219.9	365	$8,394,925,093
2022	$151.15	70,112.8	151	$3,868,038,612

106 The results for the ATSI Integration Auctions are not included in this table.
107 The results for the ATSI Integration Auctions are not included in this table.