Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 1)

February 24, 2025

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

Re: MPSC Case No. U-21775 – In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.

Dear Ms. Felice:

Enclosed for electronic filing in the above-captioned case, please find the **Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029**. A confidential version of this filing is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in PDF.

Sincerely,

Digitally signed by Gary A. Gensch, Jr.
Date: 2025.02.24 09:28:41 -05'00'

Gary A. Gensch Jr.
Phone: 517-788-0698
Email: gary.genschjr@cmsenergy.com

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.	))))))	Case No. U-21775

STATE OF MICHIGAN)
) SS
COUNTY OF JACKSON)

AFFIDAVIT OF SRIKANTH MADDIPATI

Srikanth Maddipati, being duly sworn, states that the following information and attached exhibits are true and accurate to the best of my reasonable knowledge and belief, regarding Consumers Energy Company's ("Consumers Energy" or the "Company") satisfaction of its Michigan capacity demonstration requirements:

1. I am the Vice President of Electric Supply for Consumers Energy. My responsibilities include, in part, overall responsibility for the Company's long-term and short-term electric supply planning, investments, and strategy. I received a Bachelor of Science Degree in Computer Engineering from the University of Michigan in 2004 and, concurrently, completed my Master of Science Degree in Engineering with a specialization in Signal Processing. I received a Master of Business Administration Degree ("MBA") from the Ross School of Business at the University of Michigan in 2008, where I focused on Finance and Accounting.

2. Consumers Energy is a public utility engaged in the generation, purchase, distribution, and sale of electric energy to approximately 1.9 million retail electric customers in the lower peninsula of the state of Michigan. Consumers Energy remains committed to planning

for and providing an adequate electric supply to meet the needs of Michigan homes and businesses, with reliable, flexible, and cost-effective energy.

3. The information provided in this Affidavit is based on my first-hand knowledge of the Company's long-term and short-term electric supply planning, investments, and strategy. Pursuant to Section 6w of 2016 PA 341, and as required by the Michigan Public Service Commission's ("MPSC" or the "Commission") August 22, 2024 Order in Case No. U-21393, this Affidavit is a demonstration to the Commission that the Company has sufficient electric capacity arrangements for Planning Year[1] ("PY") 2028/2029. The remainder of this Affidavit discusses the Planning Reserve Margin Requirement ("PRMR"), peak demand outlook, and the capacity resources planned to fulfill customer need.

4. Consumers Energy remains dedicated to meeting the needs of its full-service electric customers over the four-year planning period while maintaining adequate reserve margins, as detailed in this filing, with:

- Demand Response ("DR") consistent with the Company's 2021 Integrated Resource Plan ("IRP") Proposed Course of Action ("PCA") as approved in MPSC Case No. U-21090 ("IRP Settlement"). As DR programs evolve, there may be shifting of DR levels among the different programs;

- Offered capacity generated from existing resources in the applicable Michigan Zone;

- Contracted amounts of Power Purchase Agreements ("PPA") in accordance with the terms of the applicable agreements; and

- Renewable capacity from existing and new resources, as identified in this filing consistent with the Company's Renewable Energy Plan and IRP PCA.

[1] Planning Year, as defined by the Midcontinent Independent System Operator, Inc. ("MISO"), is the 12-month period commencing on June 1 of each year and concluding on May 31 of the following year.

5. Consumers Energy plans to sufficiently serve its full-service customers for the next four years and beyond. The Company's plans are outlined in the following paragraphs, covering PYs 2025/2026 through 2028/2029, and address each of the required capacity areas:

- Exhibit 1 — Utility Bundled Service Peak Demand for Michigan Midcontinent Independent System Operator, Inc. ("MISO") LRZ 7;
- Exhibit 2 — Planning Reserve Margin Requirements and Planning Resources to be Acquired (Zonal Resource Credit ("ZRC"));
- Exhibit 3 — Demand Response—Capacity Resources;
- Exhibit 4 — Company-Owned Electric Generation Resources (Confidential);
- Exhibit 5 — New or Upgraded Generation Owned;
- Exhibit 6 — Generation Resources Under PPA or Other Capacity Contract (Confidential); and
- Exhibit 7 — New or Upgraded Purchased Power.

6. MISO Module E Reports for Planning Year 2024/25

Reports from the MISO Module E Capacity Tracking tool demonstrating the unforced[2] capacity ("UCAP") confirmed by the Company for PY 2024/25 are provided as Exhibits 8 through 11.

- Exhibit 8 — Existing Owned Generation (Confidential);
- Exhibit 9 — MISO Registered Demand Response Programs (Confidential);
- Exhibit 10 — Existing Purchased Power Agreements (Confidential); and
- Exhibit 11 — Existing Transactions (Confidential).

7. Additional Exhibits

- Exhibit 12 – Relevant Tariffs; and

[2] MISO's evaluation of Loss of Load Expectation for PY 2024/25 utilized net demonstrated capacity less the three-year Equivalent Forced Outage Rate on demand, or "EFORd." The resulting capacity value is commonly referred to as "unforced."

- Exhibit 13 – Company Contact List.

In lieu of filing a copy of the customer supply contracts with this capacity demonstration, the Company agrees to make available the customer supply contracts relevant to the Commercial and Industrial Demand Response ("DR Contracts") Program and Interruptible Service ("Rate GI") Provision for the Commission Staff's ("Staff") review upon request, without Staff retaining a copy. Exhibit 13 contains the contact information of the persons designated to make available the customer supply contracts and copies of any of the Company's PPAs for review by Staff.

8. PRMR

The capacity Planning Reserve Margin ("PRM") target is the amount of capacity that a Load Serving Entity ("LSE") (such as Consumers Energy) maintains to ensure sufficient capacity exists to provide adequate electric supply in each seasonal period within a PY. The Company relies upon MISO to determine the appropriate capacity PRM that Consumers Energy should maintain. For PY 2025, the MISO Loss of Load Expectation ("LOLE") Working Group performed a LOLE study which considered the probability that various amounts of generation resources would be inadequate to serve firm demand in the MISO footprint. MISO's PY 2025-2026 Loss of Load Expectation Study Report was published on November 22, 2024. Upon determining the amount of generation resources necessary to achieve a LOLE of less than one occasion every ten years, a reserve margin (expressed as a percentage of peak firm demand) is calculated and assigned to all LSEs.

MISO's seasonal construct was accepted by the Federal Energy Regulatory Commission in September 2022, which introduced seasonal requirements to the Planning Resource Auction ("PRA"). As a result, MISO's LOLE study sets the system-wide capacity Planning Reserve Margin Unforced Capacity ("PRM UCAP") and the zonal Local Reliability Requirements

("LRR") for each season for the upcoming 2025/2026 PY. Under the MISO seasonal construct, the annual planning year is divided into four distinct seasons between June 1, 2025, and May 31, 2026, and for subsequent planning years moving forward. The seasons are Summer from June 1 – August 31, Fall from September 1 – November 30, Winter from December 1 – February 28, and Spring from March 1 - May 31.

On November 22, 2024, MISO determined seasonal PRM UCAP planning reserve margin targets for PY 2025/2026 of 7.9% for Summer, 14.9% for Fall, 18.4% for Winter, and 25.3% for Spring. The Company is filing this capacity demonstration for PY 2028/2029 using the prompt year seasonal capacity obligations and resource credit assumptions based on each individual season. The exhibits will be labeled by season (Summer, Fall, Winter, Spring) respectively for each season. The Company also forecasted load requirements for the 2028/2029 PY as it has done for prior capacity demonstrations. The Company will plan to meet the Company's PRMR and thus maintain resources to meet full-service customer capacity needs throughout the PY, including during peak load periods.

9. <u>Peak Demand</u>

The Company's historical and forecasted peak demands are shown in Exhibit 1. The values provided in Exhibit 1 are not weather-normalized. The peak demands shown in Exhibit 1 include supplying demand associated with Bundled (full-service) customers, Choice customers through Retail Open Access, and the summation of Bundled and Choice customers denoted as Service Territory peak demand.

Existing DR or Energy Waste Reduction ("EWR") resources netted against load are detailed in the section below and can be found in Exhibit 2, line 2.

The Company must plan for capacity during periods when MISO experiences its peak demand. The Company's forecast of peak bundled demand is adjusted to align with MISO's peak demand for each season, which requires application of a diversity factor as shown in Exhibit 2, lines 4 and 5. The Company's forecast of peak bundled demand is also adjusted to include transmission losses, which requires application of a transmission loss factor as shown in Exhibit 2, line 6.

Consumers Energy plans to draw on a diverse portfolio of resources to meet its annual PRMR obligation. Those resources include utility-owned generation, long-term supply contracts, EWR, and DR resources.

10. <u>Existing Generation — Owned</u>

Consumers Energy currently owns, operates, and manages resources all located within Michigan and within MISO Zone 7 and plans to offer the LSE capacity from these resources in the applicable Michigan Zone throughout the four-year planning period. A summary of the Company's forecast for its owned resources — including resource type, installed capacity, and Installed Seasonal Accreditation Capacity ("ISAC") — is provided in Exhibit 2 (by category) and Exhibit 4 (by unit).

11. <u>Existing DR or EWR Resources (Not Netted Against Load)</u>

Consumers Energy offers a suite of Demand-Side Management programs available for residential, commercial, and industrial customer classes to deliver and manage significant peak load reductions. Existing programs offered by the Company that are not netted against load and can be offered into MISO as a capacity resource include:

- Air Conditioning Peak Cycling ("ACPC") Program;
- Commercial & Industrial Demand Response (DR Contracts);

- Rate GI/GI 2 (DR Rate GI Reduce By/DR Rate GI Reduce to); and
- Smart Thermostat Program.

Existing Demand-Side Management programs not netted against load result in total load modifying resources as shown in Exhibit 2, line 18. Exhibit 3 provides additional details regarding specific amounts of MW and ZRCs expected to be credited to the Company's capacity portfolio. Exhibit 9 summarizes these DR programs with data from the MISO Module E Report for PY 2024/2025.

Transmission losses and the PRM (on a UCAP basis) were applied per MISO standard practice for registered DR capacity, as detailed in (BPM-011-r29).[3]

12. Existing DR or EWR Resources (Netted Against Load)

Existing DR and EWR programs netted against load include (Exhibit 2, line 2):

- Dynamic Peak Pricing;
- Residential Summer on-peak rate RSP;
- EWR; and
- Internal Demand Response Program Conservation Voltage Reduction.

Growth in these Demand-Side Management programs (in combination with those not netted against load) is consistent with the IRP Settlement. The applicable tariff sheets are included in Exhibit 12.

13. New or Upgraded Utility-Owned Generation

New or upgraded utility-owned generation planned for 2025 through 2028 includes new renewable resources in accordance with the Company's Renewable Energy Plan and the IRP

[3] https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

Settlement. Details for these resources including planned in-service dates, expected regulatory approval dates, and expected dates for a MISO Generator Interconnection Agreement can be found in Exhibit 5. The addition of these resources in the Company's capacity planning projections are reflected in the annual values shown in Exhibit 2 (in combination with existing units) and Exhibit 4 (by individual unit) and are based on the construction and Commercial Operation Dates ("COD") identified in Exhibit 5.

14. New DR or EWR Resources (Not Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would not be netted against load.

15. New DR or EWR Resources (Netted Against Load)

The Company does not currently have plans to develop any new DR or EWR programs that would be netted against load.

16. Existing Generation Capacity Contracts

The Company has PPAs in place for the purchase of energy, capacity, and renewable energy credits. The majority of Consumers Energy's PPAs are sourced within Michigan and within MISO Zone 7—the exception being the Heritage Garden Wind Farm, which is located in MISO Zone 2. Exhibit 6 presents a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations. The Company has several contracts in place with facilities that meet, or are expected to meet, the requirements of Qualifying Facilities ("QFs"), in accordance with the Public Utility Regulatory Policies Act of 1978 ("PURPA"), that will terminate from 2023 to 2027. Page 2 of Exhibit 6 details the QFs that have expiring contracts which are expected to be replaced with new PURPA contracts upon expiration. Exhibit 6 presents a detailed summary of the power supply contracts that supply capacity toward the Company's PRMR obligations.

17. New or Upgraded Purchased Power

The Company's New or Upgraded Purchased Power resources are presented in Exhibit 7. There are three types of resources detailed in this exhibit. First, the Company has forecasted existing PURPA-based contracts will be replaced with new PURPA-based agreements. Obligations for these contracts are projected to remain throughout the four-year planning period. The ZRCs associated with new PURPA-based contracts are identified in Exhibit 6, line 45. Second, the Company has contracted PPAs for new solar PURPA capacity per the Settlement Agreement in Case No. U-20615 ("PURPA Settlement"). Exhibits 6 and 7 present a forecast of the PURPA Settlement solar projects expected to achieve commercial operation through PY 2028. Because interconnection agreements and full construction schedules for many of these resources are not yet finalized, the expected construction dates presented in Exhibit 7 are subject to change. Finally, Exhibit 6, line 2, and Exhibit 7, line 1, show the details for the 150 MW of solar projects with a COD in June 2028 that the Company is actively procuring through its annual IRP solicitations.

Consumers Energy plans to maintain the contracted amounts of these PPAs as shown in the attached exhibits and in accordance with the terms of the applicable agreements throughout the four-year planning period.

18. Forward ZRC Contracts

As shown on Exhibit 6, line 1, the Company has a three-year contract with Midland Cogeneration Venture Limited Partnership to provide 100 MW for each of the PY's 2025, 2026, and 2027. Additionally, the Company has contracted for capacity through the 2024 Reverse Capacity Auction, for PY's 2025 and 2026. This is shown in Exhibit 6, line 3.

19. Planning Resource Auction Purchases

The Company projects PRA purchases for the Winter of PY 2028, as well as the Fall of PY's 2025, 2026, and 2028 as shown in the Winter and Fall Exhibits 2, line 34.

If sworn as a witness, I would testify as set forth above.

Sri M.

Srikanth Maddipati

Subscribed and sworn to before me this 24th day of February 2025.

Crystal L. Chacon

Crystal L. Chacon, Notary Public
State of Michigan, County of Eaton
My Commission Expires: 05/25/30
Acting in the County of Jackson

SUMMER
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	8,458	8,458	8,505	8,680	8,905
2	Choice, Coincident to Service Territory	449	384	461	457	457
3	Bundled (line 1 - line 2)	8,009	8,074	8,044	8,223	8,449
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	8,147	8,168	8,214	8,382	8,600
5	Choice, Coincident to Service Territory	433	370	446	441	441
6	Bundled (line 4 - line 5)	7,714	7,797	7,768	7,941	8,159

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

	(a)	(b)	(c)	(d)	(e)
Line		PY 2025-26	PY 2026-27	PY 2027-28	PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	8,074	8,044	8,223	8,449
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	1,023	1,144	1,157	1,185
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	7,051	6,900	7,066	7,263
4	Load Diversity Factor coincident to MISO, %.	96.57%	96.57%	96.57%	96.57%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,809	6,663	6,823	7,014
6	Transmission Losses, %	3.30%	3.30%	3.30%	3.30%
7	Planning Reserve Margin % UCAP Basis	7.90%	9.40%	9.60%	9.50%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,590	7,530	7,725	7,934
9	Company Owned, In-State, Non-Intermittent, ZRC	4,321	4,163	4,163	4,166
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	178	527	716	1,201
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	12	14	16	16
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,528	4,722	4,913	5,401
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	651	684	691	691
19	PPA, In-State, Non-Intermittent, ZRC	1,665	1,585	1,571	1,407
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	30	28	24	24
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	393	658	903	978
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	23	23	23	23
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	22	22
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	240	240	240	240
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,351	2,539	2,782	2,694
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	-
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,625	8,015	8,387	8,785
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	35	484	662	851

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 3 - Demand Response - Capacity Resources - Summer Season

	(a)	(b)	(c)	(d)	(e)
Line		Demand Response Program Name	Demand Response Program (MW)	Credit Transmission Losses and PRM (SAC)	Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	35	4	39
2		Rate EIP	-	-	-
3		DR CONTRACTS	240	28	268
4		DR RATE GI REDUCE BY	16	2	18
5		DR RATE GI REDUCE TO	249	29	278
6		Smart Thermostat Program (STP)	44	5	49
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				651.4
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
10		Rate EIP	10	1	11
11		DR CONTRACTS	220	29	249
12		DR RATE GI REDUCE BY	16	2	19
13		DR RATE GI REDUCE TO	249	32	282
14		Smart Thermostat Program (STP)	75	10	85
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				684.3
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
18		Rate EIP	15	2	17
19		DR CONTRACTS	220	29	249
20		DR RATE GI REDUCE BY	16	2	19
21		DR RATE GI REDUCE TO	249	33	282
22		Smart Thermostat Program (STP)	75	10	85
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				691.2
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	35	5	40
26		Rate EIP	15	2	17
27		DR CONTRACTS	220	29	249
28		DR RATE GI REDUCE BY	16	2	19
29		DR RATE GI REDUCE TO	249	33	282
30		Smart Thermostat Program (STP)	75	10	85
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				690.6

<u>EXHIBIT 4</u>
<u>IS *CONFIDENTIAL* AND BEING FILED</u>
<u>UNDER SEAL WITH THE MPSC</u>

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 5 - New or Upgraded Generation Owned - Summer Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/31/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	81.90%	18	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 7 - New or Upgraded Purchased Power - Summer Season

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	**Electric Generator Name**	**Fuel or Renewable Type**	**Added Unit Nameplate MWs**	**Class Average / MISO Capacity Credit**	**Added ZRCs**	**Expected COD**	**Planned MPSC Regulatory Approval Date**	**Planned MISO Interconnection Queue Date**	**Planned MISO Interconnection Agreement Approval**	**Construction Start Date**	**Construction End Date**
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	30.00%	14	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Storage	100	5.00%	95	May 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	82.19%	20	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027
15											
16											

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

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

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

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

FALL
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

Actual and Forecast (MW)

	(a)	(b)	(c)	(d)	(e)	(f)
Line		**PY 2024-25**	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	7,322	7,419	7,605	7,840	7,858
2	Choice, Coincident to Service Territory	531	397	499	493	485
3	Bundled (line 1 - line 2)	6,791	7,022	7,106	7,346	7,373
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	7,224	7,318	7,501	7,733	7,751
5	Choice, Coincident to Service Territory	524	391	492	487	479
6	Bundled (line 4 - line 5)	6,700	6,927	7,009	7,247	7,272

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

	(a)	(b)	(c)	(d)	(e)
Line		**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	7,022	7,106	7,346	7,373
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	842	951	969	1,003
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	6,180	6,155	6,378	6,370
4	Load Diversity Factor coincident to MISO, %.	98.64%	98.64%	98.64%	98.64%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	6,096	6,071	6,291	6,284
6	Transmission Losses, %	4.50%	4.50%	4.50%	4.50%
7	Planning Reserve Margin % UCAP Basis	14.90%	15.30%	15.90%	15.70%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	7,320	7,315	7,620	7,597
9	Company Owned, In-State, Non-Intermittent, ZRC	3,852	3,753	3,990	3,396
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	18	18	18	18
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	209	558	747	1,230
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	13	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,089	4,341	4,770	4,659
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	381	338	346	345
19	PPA, In-State, Non-Intermittent, ZRC	1,649	1,562	1,545	1,388
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	31	29	25	25
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	397	662	907	982
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	8	8	8	8
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	6	22	22
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	148	148	148	148
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	2,233	2,415	2,656	2,573
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	105	70	-	-
34	Planned Capacity Purchases, ZRC	512	151	-	20
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,320	7,315	7,772	7,597
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	(0)	(0)	152	(0)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 3 - Demand Response - Capacity Resources - Fall Season

Line	(a)	(b) Demand Response Program Name	(c) Demand Response Program (MW)	(d) Credit Transmission Losses and PRM (SAC)	(e) Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	46	9	55
4		DR RATE GI REDUCE BY	16	3	20
5		DR RATE GI REDUCE TO	255	51	306
6					-
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				381.3
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
10		Rate EIP	10	2	12
11		DR CONTRACTS	-	-	-
12		DR RATE GI REDUCE BY	15	3	18
13		DR RATE GI REDUCE TO	255	52	308
14					-
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				337.8
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
18		Rate EIP	15	3	18
19		DR CONTRACTS	-	-	-
20		DR RATE GI REDUCE BY	15	3	18
21		DR RATE GI REDUCE TO	255	54	309
22					-
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				345.7
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
26		Rate EIP	15	3	18
27		DR CONTRACTS	-	-	-
28		DR RATE GI REDUCE BY	15	3	18
29		DR RATE GI REDUCE TO	255	53	309
30					-
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				345.1

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

Exhibit 5 - New or Upgraded Generation Owned - Fall Season

Line	(a) Electric Generator Name	(b) Fuel or Renewable Type	(c) Added Unit Nameplate MWs	(d) Class Average / MISO Capacity Credit	(e) Added ZRCs	(f) Expected COD	(g) Planned MPSC Regulatory Approval Date	(h) Planned MISO Interconnection Agreement Approval	(i) Construction Start Date	(j) Construction End Date	
1	IRP Settlement Storage	Battery Storage	75	5.00%	71	12/31/2026	N/A	N/A	Q4 2025	Q4 2026	[1]
2	Muskegon Solar	Solar	250	50.00%	125	6/1/2026	complete	complete	Q3 2023	Q4 2025	
3	Mustang Mile Solar Project	Solar	150	50.00%	75	12/31/2026	complete	complete	Q4 2022	Q4 2026	[2]
4	Washtenaw Solar Project	Solar	150	50.00%	75	12/31/2027	complete	complete	Q2 2025	Q4 2027	[3]
5	Armstrong Battery	Battery Storage	3	5.00%	2	12/21/2026	N/A	N/A	Q2 2025	Q4 2026	
6	Karn Solar	Solar	85	50.00%	43	12/30/2026	Q4 2024 Submittal	Q1 2026	Q2 2025	Q4 2026	
7	Sunfish Solar	Solar	309	50.00%	155	3/31/2026	complete (Contract)	Q4 2025	Q2 2024	Q4 2025	
8	Spring Creek Solar	Solar	140	50.00%	70	6/1/2026	Q2 2024 Submittal	Q1 2026	Q2 2025	Q2 2026	
9	300 MW 2028 Solar - Owned	Solar	300	50.00%	150	6/1/2028	TBD	TBD	TBD	TBD	
10	147 MW 2028 Solar - Owned	Solar	147	50.00%	74	6/1/2028	Q4 2025 Submittal	Q2 2026	Q2 2025	Q2 2028	
11	220 MW 2028 Solar - VGP	Solar	220	50.00%	110	12/31/2027	Q2 2025 Submittal	Q1 2026	Q2 2025	Q4 2027	
12	117 MW 2028 Solar - VGP	Solar	117	50.00%	59	12/31/2027	Q3 2025 Submittal	Q2 2026	Q4 2027	Q4 2027	
13	100 MW 2028 Wind - Owned	Wind	100	84.40%	16	6/1/2028	TBD	TBD	TBD	TBD	

Notes:

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

EXHIBIT 6

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 7 - New or Upgraded Purchased Power - Fall Season

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line	**Electric Generator Name**	**Fuel or Renewable Type**	**Added Unit Nameplate MWs**	**Class Average / MISO Capacity Credit**	**Added ZRCs**	**Expected COD**	**Planned MPSC Regulatory Approval Date**	**Planned MISO Interconnection Queue Date**	**Planned MISO Interconnection Agreement Approval**	**Construction Start Date**	**Construction End Date**
1	150 MW 2028 Solar - PPA	Solar	150.0	50.00%	75	June 2028	TBD	TBD	TBD	TBD	TBD
2	Blue Elk Solar II	Solar	20	50.00%	10	April 2024	Complete	n/a	n/a	May 2023	March 2024
3	Freshwater Solar 1	Solar	300.0	50.00%	150	June 2027	Complete	Complete	Complete	Complete	May 2027
4	Heartwood Solar	Solar	150	50.00%	75	March 2026	Complete	Complete	Complete	August 2024	March 2026
5	Jackson County Solar	Solar	125	50.00%	63	May 2025	Complete	Complete	Complete	September 2023	May 2025
6	Lake City Solar	Solar	2	50.00%	1	November 2024	Complete	n/a	n/a	January 2023	June 2024
7	Morey Road Solar	Solar	2	50.00%	1	November 2024	Complete	Complete	n/a	January 2023	June 2024
8	River Fork Solar	Solar	100	50.00%	50	October 2024	Complete	Complete	Complete	November 2021	March 2024
9	Surbrook Solar	Solar	10	50.00%	5	September 2024	Complete	n/a	n/a	July 2023	March 2024
10	Surrey Road Solar	Solar	2	50.00%	1	January 2025	Complete	n/a	n/a	January 2023	June 2024
11	Tibbits Energy Storage	Solar	100	5.00%	95	June 2025	Complete	Complete	Complete	July 2024	May 2025
12	Distributed Generation Aggregate	Solar	114	94.65%	6	June 2025	Complete	Complete	Complete	Complete	Complete
13	Century Oaks	Storage	200	5.00%	190	June 2026	Complete	Complete	Complete	June 2025	January 2026
14	Voyager Energy Storage	Storage	100	5.00%	95	June 2027	Complete	Complete	Complete	June 2026	January 2027

<u>EXHIBIT 8</u>
<u>IS *CONFIDENTIAL* AND BEING FILED</u>
<u>UNDER SEAL WITH THE MPSC</u>

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

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

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

WINTER
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

Actual and Forecast (MW)

Line	(a)	(b)	(c)	(d)	(e)	(f)
		PY 2024-25	**PY 2025-26**	**PY 2026-27**	**PY 2027-28**	**PY 2028-29**
		Forecast	Forecast	Forecast	Forecast	Forecast
	Peak Demand (MW)					
1	Service Territory	6,286	6,407	6,608	6,695	6,788
2	Choice, Coincident to Service Territory	296	386	407	385	397
3	Bundled (line 1 - line 2)	5,989	6,021	6,200	6,310	6,391
	Coincident to MISO Sys.Peak Demand (MW)					
4	Service Territory	6,200	6,327	6,525	6,611	6,703
5	Choice, Coincident to Service Territory	292	381	402	381	392
6	Bundled (line 4 - line 5)	5,908	5,946	6,123	6,231	6,311

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

	(a)	(b)	(c)	(d)	(e)
Line		PY 2025-26	PY 2026-27	PY 2027-28	PY 2028-29
1	Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (from Ex. 1)	6,021	6,200	6,310	6,391
2	Internal Demand Response Programs that are applied as an adjustment to the Peak forecast, MW	788	879	895	889
3	Adjusted Forecasted Bundled (or AES) Non-Coincident Peak Demand, MW (line 1 - line 2)	5,234	5,321	5,414	5,502
4	Load Diversity Factor coincident to MISO, %.	98.75%	98.75%	98.75%	98.75%
5	Adjusted Forecasted Bundled (or AES) Coincident Peak Demand, MW (line 3 x line 4)	5,168	5,255	5,346	5,433
6	Transmission Losses, %	3.00%	3.00%	3.00%	3.00%
7	Planning Reserve Margin % UCAP Basis	18.40%	27.00%	26.80%	26.50%
8	Total Planning Reserve Margin Requirement, ZRC ((line 5) x (1 + line 6) x (1 + line 7))	6,303	6,873	6,982	7,079
9	Company Owned, In-State, Non-Intermittent, ZRC	4,384	4,134	4,320	4,135
10	Company Owned, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
11	Company Owned, In-State, Non-Intermittent (BTMG), ZRC	17	17	17	17
12	Company Owned, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
13	Company Owned, In-State, Intermittent, ZRC	224	259	342	442
14	Company Owned, Out-of-State, Intermittent, ZRC	-	-	-	-
15	Company Owned, In-State, Intermittent (BTMG), ZRC	11	13	15	15
16	Company Owned, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
17	Total Company Owned Generation, ZRC (sum of lines 9-16)	4,636	4,423	4,695	4,610
18	Total Load Modifying Resources, Treated as Capacity, ZRC (from Ex. 3)	389	373	379	378
19	PPA, In-State, Non-Intermittent, ZRC	1,603	1,603	1,548	1,415
20	PPA, Out-of-State, Non-Intermittent, ZRC	-	-	-	-
21	PPA, In-State, Non-Intermittent (BTMG), ZRC	27	25	22	22
22	PPA, Out-of-State, Non-Intermittent (BTMG), ZRC	-	-	-	-
23	PPA, In-State, Intermittent, ZRC	282	480	590	592
24	PPA, Out-of-State, Intermittent, ZRC	-	-	-	-
25	PPA, In-State, Intermittent (BTMG), ZRC	5	5	4	4
26	PPA, Out-of-State, Intermittent (BTMG), ZRC	-	-	-	-
27	New Contracts w/ Existing PURPA QFs, ZRC - In-State	-	5	23	23
28	New Contracts w/ Solar PURPA QFs, ZRC - In-State	6	6	6	6
29	Other Forward Capacity Contract, ZRC - In-State	-	-	-	-
30	Other Forward Capacity Contract, ZRC - Out-of-State	-	-	-	-
31	Total PPA, ZRC (sum of lines 19-30)	1,923	2,123	2,192	2,061
32	Net Load Switching, ZRC	-	-	-	-
33	Capacity Purchases, ZRC	95	70	-	-
34	Planned Capacity Purchases, ZRC	-	-	-	30
35	Total Planning Resources, ZRC (line 17 + line 18 + lines 31 through 34)	7,042	6,989	7,266	7,079
36	UCAP Surplus/(Shortfall), ZRC (line 35 - line 8)	740	116	283	(0)

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 3 - Demand Response - Capacity Resources - Winter Season

	(a)	(b)	(c)	(d)	(e)
Line		Demand Response Program Name	Demand Response Program (MW)	Credit Transmission Losses and PRM (SAC)	Total ZRC per Program Name
1	**PY 2025-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
2		Rate EIP	-	-	-
3		DR CONTRACTS	43	9	52
4		DR RATE GI REDUCE BY	16	4	20
5		DR RATE GI REDUCE TO	259	57	316
6					-
7					-
8	**Total Demand Response - Capacity Resources PY 2025-2026 (ZRC)**				388.7
9	**PY 2026-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
10		Rate EIP	10	3	13
11		DR CONTRACTS	-	-	-
12		DR RATE GI REDUCE BY	15	5	20
13		DR RATE GI REDUCE TO	259	80	339
14					-
15					-
16	**Total Demand Response - Capacity Resources PY 2026-2027 (ZRC)**				372.5
17	**PY 2027-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
18		Rate EIP	15	5	20
19		DR CONTRACTS	-	-	-
20		DR RATE GI REDUCE BY	15	5	20
21		DR RATE GI REDUCE TO	259	79	339
22					-
23					-
24	**Total Demand Response - Capacity Resources PY 2027-2028 (ZRC)**				378.5
25	**PY 2028-SAC**	Air Conditioning Peak Cycling(ACPC)	-	-	-
26		Rate EIP	15	5	20
27		DR CONTRACTS	-	-	-
28		DR RATE GI REDUCE BY	15	5	20
29		DR RATE GI REDUCE TO	259	79	338
30					-
31					-
32	**Total Demand Response - Capacity Resources PY 2028-2029 (ZRC)**				377.6

Attachment J

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 5 - New or Upgraded Generation Owned - Winter Season

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

Notes:

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 7 - New or Upgraded Purchased Power - Winter Season

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

<u>EXHIBIT 8</u>
<u>IS *CONFIDENTIAL* AND BEING FILED UNDER SEAL WITH THE MPSC</u>

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

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

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

SPRING
EXHIBITS 1-11

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

Actual and Forecast (MW)

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 3 - Demand Response - Capacity Resources - Spring Season

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 5 - New or Upgraded Generation Owned - Spring Season

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

Notes:

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

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

MICHIGAN PUBLIC SERVICE COMMISSION
Consumers Energy Company

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

Exhibit 7 - New or Upgraded Purchased Power - Spring Season

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

<u>EXHIBIT 8</u>
<u>IS *CONFIDENTIAL* AND BEING FILED</u>
<u>UNDER SEAL WITH THE MPSC</u>

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

EXHIBIT 10

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

<u>EXHIBIT 11</u>
<u>IS *CONFIDENTIAL* AND BEING FILED</u>
<u>UNDER SEAL WITH THE MPSC</u>

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

Availability:

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

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

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

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

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

Nature of Service:

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

Monthly Rate:

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

Energy Charge:

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

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

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

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

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

(Continued on Sheet No. D-15.00)

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

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

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-14.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

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

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

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

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

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

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

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

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

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

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

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

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

Senior Citizen Service Provision (RSC):

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

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

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

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

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

(Continued on Sheet No. D-16.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-15.00)

Monthly Rate: (Contd)

Device Cycling Program

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

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

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

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

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

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

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

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

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

(Continued on Sheet No. D-17.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-16.00)

Monthly Rate: (Contd)

Peak Reward

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

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

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

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

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

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

Critical Peak Price

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

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

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

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

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

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

Self-Generation (SG):

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

(Continued on Sheet No. D-18.00)

RESIDENTIAL SUMMER ON-PEAK BASIC RATE RSP

(Continued From Sheet No. D-17.00)

Monthly Rate: (Contd)

Net Metering Program:

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

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

Distributed Generation Program:

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

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

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

General Terms:

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

Schedule of On-Peak and Off-Peak Hours:

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

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

Saturday and Sunday are Off-Peak.

Minimum Charge:

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

Due Date and Late Payment Charge:

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

Term and Form of Contract:

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

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

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

RESIDENTIAL SMART HOURS RATE RSH

Availability:

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

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

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

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

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

Nature of Service:

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

Monthly Rate:

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

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

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

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

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

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

(Continued on Sheet No. D-36.10)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.00)

Income Assistance Service Provision (RIA):

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

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

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

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

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

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

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

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

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

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

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

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

Senior Citizen Service Provision (RSC):

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

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

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

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

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

(Continued on Sheet No. D-37.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-36.10)

Monthly Rate: (Contd)

Device Cycling Program

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

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

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

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

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

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

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

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

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

(Continued on Sheet No. D-38.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-37.00)

Monthly Rate: (Contd)

Peak Reward

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

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

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

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

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

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

Critical Peak Price

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

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

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

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

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

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

Self-Generation (SG):

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

(Continued on Sheet No. D-39.00)

RESIDENTIAL SMART HOURS RATE RSH

(Continued From Sheet No. D-38.00)

Monthly Rate: (Contd)

Net Metering Program:

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

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

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

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1.*, Residential Electric Vehicle Program.

General Terms:

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

Minimum Charge:

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

Due Date and Late Payment Charge:

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

Schedule of On-Peak and Off-Peak Hours:

The following schedule shall apply Monday through Friday, including weekday holidays when applicable:

Summer: June 1 through September 30

Winter: October 1 through May 31

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

Saturday and Sunday are Off-Peak.

Term and Form of Contract:

Service under this rate shall not require a written contract.

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

Eighth Revised Sheet No. D-40.00
Cancels Seventh Revised Sheet No. D-40.00

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

Availability:

The Residential Nighttime Savers Rate is voluntary and available for service rendered on and after June 1, 2021 to Full Service residential customers who have the required metering equipment and infrastructure installed. The Company will furnish, install, maintain and own the required equipment at the customers' premises at the Company's expense.

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

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

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

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

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

Nature of Service:

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

Monthly Rate:

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Super Off-Peak - Summer	*$0.072762*	*$0.004114*	*$0.076876*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Summer	*$0.096349*	*$0.006757*	*$0.103106*	per kWh for all Off-Peak kWh between June 1 and September 30
On-Peak - Summer	*$0.132272*	*$0.008912*	*$0.141184*	per kWh for all On-Peak kWh between June 1 and September 30
Super Off-Peak - Winter	*$0.070062*	*$0.003564*	*$0.073626*	per kWh for all Super Off-Peak kWh between June 1 and September 30
Off-Peak - Winter	*$0.091004*	*$0.004969*	*$0.095973*	per kWh for all Off-Peak kWh between October 1 and May 31
On-Peak - Winter	*$0.091448*	*$0.005139*	*$0.096587*	per kWh for all On-Peak kWh between October 1 and May 31

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

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

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

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

(Continued on Sheet No. D-40.50)

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

Effective for service rendered on
and after March 15, 2024

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

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.00)

Monthly Rate: (Contd)

Income Assistance Service Provision (RIA):

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

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

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

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

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

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

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

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

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

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

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

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

(Continued on Sheet No. D-41.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-40.50)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

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

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

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

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

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

Residential Plug-In Electric Vehicle Only Credit (REV):

When service is supplied for Level 2 Charging of a separately metered electric vehicle, a credit shall be applied during all billing months. Electric usage for the separately metered electric vehicle will be billed under the Residential Nighttime Savers Rate.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 50 amperes or 9.6 kW.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this credit. Low-speed electric vehicles including golf carts are not eligible for this credit even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for this credit.

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

Residential Plug-In Electric Vehicle Only Credit: $(8.00) per customer per month

Device Cycling Program:

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

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

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

(Continued on Sheet No. D-42.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-41.00)

Monthly Rate: (Contd)

Device Cycling Program: (Contd)

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

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

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

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

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

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

Peak Reward:

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

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

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

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

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

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

(Continued on Sheet No. D-43.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-42.00)

Monthly Rate: (Contd)

Critical Peak Price:

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

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

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

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

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

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

Self-Generation (SG):

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

Net Metering Program:

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

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

Distributed Generation Program:

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

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

Green Generation Program:

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

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

(Continued on Sheet No. D-44.00)

RESIDENTIAL NIGHTTIME SAVERS RATE RPM

(Continued From Sheet No. D-43.00)

Monthly Rate: (Contd)

Renewable Energy Credit (REC) Programs:

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

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

Residential Electric Vehicle Program:

The Residential Electric Vehicle Program is available to any eligible customer as described in Rule C*19.1*., Residential Electric Vehicle Program.

General Terms:

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

Minimum Charge:

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

Due Date and Late Payment Charge:

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

Schedule of Hours:

The following schedule shall apply Monday through Friday including weekday holidays.

Summer: June 1 through September 30
Winter: October 1 through May 31

(1)	Super Off-Peak Hours:	11:00 PM to 6:00 AM
(2)	Off-Peak Hours:	6:00 AM to 2:00 PM and 7:00 PM to 11:00 PM
(3)	On-Peak Hours:	2:00 PM to 7:00 PM

Saturday and Sunday are Super Off-Peak.

Term and Form of Contract:

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

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

Availability:

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

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

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

This rate is only available to customers electing a Non-Transmitting Meter in accordance with Rule C5.5, Non-Transmitting Meter Provision, customers with a Non-Communicating Advanced Metering Infrastructure (AMI) Meter, or customers determined to be eligible at the Company's sole discretion.

A Non-Communicating AMI meter is unable to consistently transmit interval data to the Company's billing system. Non-Communicating Meters are determined at the Company's sole discretion and are subject to a minimum of one communication review per calendar year. When the meter has been determined to successfully communicate interval data, the customer will be notified and transferred to Residential Service Secondary On-Peak Summer Basic Rate RSP. The transfer to Rate RSP shall not occur between June 1 and September 30.

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

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

Nature of Service:

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

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

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

Energy Charge:

Non-Capacity	Capacity	Total	
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for the first 600 kWh per month during the billing months of June - September
$ *0.132272*	$ *0.008912*	$*0.141184*	per kWh for all kWh over 600 kWh per month during the billing months of June - September
$ *0.082887*	$ *0.004667*	$*0.087554*	per kWh for all kWh during the billing months of October-May

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

(Continued on Sheet No. D-44.20)

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.10)

Monthly Rate: (Contd)

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

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

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

Income Assistance Service Provision (RIA):

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

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

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

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

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

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

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

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

Low Income Assistance Credit (LIAC):

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

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

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

The monthly credit for LIAC shall be applied as follows:

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

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

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

(Continued on Sheet No. D-44.30)

RESIDENTIAL SERVICE SECONDARY NON-TRANSMITTING METER RATE RSM

(Continued From Sheet No. D-44.20)

Monthly Rate: (Contd)

Senior Citizen Service Provision (RSC):

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

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

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

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

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

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

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

Minimum Charge:

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

Due Date and Late Payment Charge:

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

Term and Form of Contract:

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

Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 3)

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

Sixth Revised Sheet No. D-45.00
Cancels Fifth Revised Sheet No. D-45.00

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

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

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

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

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.094566*	$*0.006246*	$*0.100812*	per kWh for all kWh during the billing months of June-September
$*0.082686*	$*0.004372*	$*0.087058*	per kWh for all kWh during the billing months of October-May

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

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

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$*0.057594*	per kWh for all kWh

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

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-46.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-45.00)

Monthly Rate: (Contd)

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

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

(Continued on Sheet No. D-47.00)

GENERAL SERVICE SECONDARY RATE GS

(Continued From Sheet No. D-46.00)

Monthly Rate: (Contd)

Net Metering Program:

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

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

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

Green Generation Program:

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

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

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

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

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

Non-Transmitting Meter Provision:

A customer who chooses a non-transmitting meter is subject to the provisions contained in Rule C5.5, Non-Transmitting Meter Provision.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Net Metering Program, (vii) service under the Demand Response Program or (viii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems. Standby service shall be provided on this rate for secondary customers with solar installations equal to or greater than 150 kW.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

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

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

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

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	$0.073219	$0.004064	$0.077283	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	$0.098057	$0.006297	$0.104354	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	$0.132113	$0.007579	$0.139692	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	$0.071813	$0.003541	$0.075354	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	$0.091062	$0.004740	$0.095802	per kWh for all On-Peak kWh during the billing months of October-May

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

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

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.057594	per kWh for all kWh for a Full Service Customer

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

(Continued on Sheet No. D-49.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-48.00)

Monthly Rate (Contd)

Schedule of Hours

The following schedule shall apply Monday through Friday (except holidays designated by the Company). Weekends and holidays are off-peak. Holidays designated by the Company include: New Year's Day – January 1, Memorial Day – Last Monday in May, Independence Day – July 4, Labor Day – First Monday in September, Thanksgiving Day – Fourth Thursday in November and Christmas Day – December 25. Whenever January 1, July 4, or December 25 falls on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Summer Billing Months of June through September:

(1)	Off-Peak Hours	12:00 AM to 7:00 AM and 11:00 PM to 12:00 AM
(2)	Mid-Peak Hours	7:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
(3)	On-Peak Hours	2:00 PM to 6:00 PM

Winter Billing Months of January through May and October through December:

(1)	Off-Peak Hours	11:00 PM to 7:00 AM
(2)	On-Peak Hours	7:00 AM to 11:00 PM

Resale Service Provision

Subject to any restrictions, the provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit:	$(0.000848)	per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

(Continued on Sheet No. D-50.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-49.00)

Monthly Rate: (Contd)

General Service Secondary Interruptible (GSI) Provision: (Contd)

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

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

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit: $(0.017673) per kWh for all kWh

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG)

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

Distributed Generation Program:

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

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

(Continued on Sheet No. D-50.10)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

(Continued From Sheet No. D-50.00)

Monthly Rate: (Contd)

Green Generation Program:

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

A customer who participates in the Green Generation Program is subject to the provision contained in Rule C 10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

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

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

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges. Special Minimum Charges shall be billed in accordance with Rule C15., Special Minimum Charges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) for Special Minimum Charges, (iv) service for lighting or where mobile home parks are involved, (v) service under the Educational Institution Service Provision, (vi) service under the Demand Response Program or (vii) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

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

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: These Charges are applicable to Full Service customers.

Peak Demand Charge:

Non-Capacity	Capacity	Total	
$25.91	*$1.69*	*$27.60*	per kW for all kW of Peak Demand during the billing months of June-September
$15.05	*$1.50*	*$16.55*	per kW for all kW of Peak Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$0.032152	per kWh for all kWh during the billing months of June-September
$0.029959	per kWh for all kWh during the billing months of October-May

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

Delivery Charges: These Charges are applicable to Full Service and Retail Open Access (ROA) customers.

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.00	per kW for all kW of Peak Demand
Distribution Charge:	*$0.043515*	per kWh for all kWh

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

(Continued on Sheet No. D-52.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-51.00)

Monthly Rate: (Contd)

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	***Penalty***
0.800 to 0.849	*0.50%*
0.750 to 0.799	*1.00%*
0.700 to 0.749	*2.00%*
Below 0.700	*3% first 2 months*

Adjustment for Power Factor shall not be applied when the Peak Demand is based a Minimum Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Peak Demand:

The Peak Demand shall be the Kilowatts (kW) supplied during the period of highest use in the billing month but not less than 60% of the highest Peak Demand created during the preceding billing months of June through September, nor less than 5 kW.

The Company reserves the right to make special determination of the Peak Demand and/or the Minimum Charge should the equipment which creates momentary high demands be included in the customer's installation.

When a customer guarantees a Peak Demand of 100 kW, the current month Peak Demand shall be the greatest of (1) the highest actual Peak Demand created during the on-peak hours in the current billing month, (2) 1/3 of the highest Peak Demand created during the off-peak hours in the current billing month, (3) 100 kW, or (4) 60% of the highest Peak Demand created during the previous billing months of June through September. For the purpose of applying the 60% provision, only the Peak Demands created after a customer guarantees 100 kW minimum shall be considered. On-peak and off-peak hours are contained in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Secondary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-53.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-52.00)

Monthly Rate: (Contd)

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Education Institution Credit: $ (0.000690) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

General Service Secondary Interruptible (GSI) Provision:

This provision is available to no more than 200 Full Service Customers desiring interruptible service in conjunction with service taken under General Service Secondary Demand Rate GSD or General Service Secondary Time-of-Use Rate GSTU. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* Service to interruptible load shall be taken through separately metered circuits and permanently wired. The design and method of installation for application of this rate shall be subject to the approval of the Company.

Any load designated as interruptible by the customer is subject to Midcontinent Independent System Operator's, Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electric Procedure or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status.

Under this provision, the customer shall be interrupted at any time the Company deems it necessary to maintain system integrity. Service to interruptible load shall not be transferred to firm service circuits to avoid interruption. The Company shall provide the Customer at least 30 minutes notice in advance of a required interruption. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GSI provision. Failure by a customer to comply with a system integrity interruption order of the Company shall be considered unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of demand created during the interruption period in addition to the prescribed monthly rate.

This rate is not available for loads that are primarily off-peak, for example parking lot lighting. Participation requires a minimum term of one year.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

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

Capacity Credit: These charges are applicable to Full Service Customers.

Interruptible Credit:	$(7.00)	per kW for all kW of Peak Demand during the billing months of June - September
	$(6.00)	per kW for all kW of Peak Demand during the billing months of October - May

(Continued on Sheet No. D-53.50)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. D-53.00)

Monthly Rate: (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

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

Net Metering Program:

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

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

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

(Continued on Sheet No. D-54.00)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

(Continued From Sheet No. *D-53.50*)

Monthly Rate: (Contd)

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall not require a written contract except for: (i) resale service, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Net Metering program, (v) *service under the Demand Response Program or (vi)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

GENERAL SERVICE PRIMARY RATE GP

Availability:

As of January 1, 2021, this rate is closed to new business other than for service to DCFC fast charging stations. Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

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

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

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

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.089336	*$0.005350*	*$0.094686*	per kWh for all kWh during the billing months of June-September
$0.078143	*$0.003744*	*$0.081887*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.088260	*$0.005267*	*$0.093527*	per kWh for all kWh during the billing months of June-September
$0.077219	*$0.003687*	*$0.080906*	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

Non-Capacity	Capacity	Total	
$0.087186	*$0.005192*	*$0.092378*	per kWh for all kWh during the billing months of June-September
$0.076290	*$0.003634*	*$0.079924*	per kWh for all kWh during the billing months of October-May

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

(Continued on Sheet No. D-56.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-55.00)

Monthly Rate (Contd)

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

System Access Charge: $100.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)
Distribution Charge: $0.020826 per kWh for all kWh

Charges for Customer Voltage Level 2 (CVL2)
Distribution Charge: $0.009094 per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL1)
Distribution Charge: $0.002634 per kWh for all kWh

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

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period . Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

(Continued on Sheet No. D-57.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-56.00)

Monthly Rate (Contd)

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit.

The monthly credit for the substation ownership shall be applied as follows:

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

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $ (0.001741) per kWh for all kWh

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $ (0.001309) per kWh for all kWh

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kWh.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Educational Institution Credit: $(0.000533) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Self-Generation (SG):

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

(Continued on Sheet No. D-58.00)

GENERAL SERVICE PRIMARY RATE GP

(Continued From Sheet No. D-57.00)

Monthly Rate (Contd)

Net Metering Program:

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

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

A customer who participates in the Distributed Generation Program is subject to the provisions contained in Rule

C 11.3., Distributed Generation Program.

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customers as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms:

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

Minimum Charge:

The System Access charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

For customers with monthly demands of 300 kW or more, all service under this rate may require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Green Generation Program, (ii) service under the Educational Institution provision, (iii) service under the Resale Service Provision, (iv) service under the Net Metering Program, (v) service under the Demand Response Program or (vi) at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service

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

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: These charges are applicable to Full Service Customers
<u>Charges for Customer Voltage Level 3 (CVL 3)</u>

Demand Charge:

Non-Capacity	Capacity	Total	
$*16.51*	$*1.81*	$*18.32*	per kW of On-Peak Billing Demand during the billing months of June-September
$*14.26*	$*1.68*	$*15.94*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity	
$*8.17*	per kW of On-Peak Billing Demand during the billing months of June-September
$*7.60*	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity	
$*0.045475*	per kWh for all On-Peak kWh during the billing months of June-September
$*0.029051*	per kWh for all Off-Peak kWh during the billing months of June-September
$*0.034757*	per kWh for all On-Peak kWh during the billing months of October-May
$*0.030290*	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-60.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-59.00)

Monthly Rate: (Contd)

Power Supply Charges: These charges are applicable to Full Service Customers (Contd)

Charges for Customer Voltage Level 2 (CVL 2)

Demand Charge:

Non-Capacity	Capacity	Total	
$16.33	*$1.79*	*$18.12*	per kW of On-Peak Billing Demand during the billing months of June-September
$14.10	*$1.65*	*$15.75*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity

$8.04	per kW of On-Peak Billing Demand during the billing months of June-September
$7.49	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity

$0.044977	per kWh for all On-Peak kWh during the billing months of June-September
$0.028732	per kWh for all Off-Peak kWh during the billing months of June-September
$0.034376	per kWh for all On-Peak kWh during the billing months of October-May
$0.029959	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL 1)

Demand Charge:

Non-Capacity	Capacity	Total	
$16.14	*$1.76*	*$17.90*	per kW of On-Peak Billing Demand during the billing months of June-September
$13.94	*$1.63*	*$15.57*	per kW of On-Peak Billing Demand during the billing months of October-May

Transmission Charge:

Non-Capacity

$7.93	per kW of On-Peak Billing Demand during the billing months of June-September
$7.38	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charge:

Non-Capacity

$0.044461	per kWh for all On-Peak kWh during the billing months of June-September
$0.028403	per kWh for all Off-Peak kWh during the billing months of June-September
$0.033982	per kWh for all On-Peak kWh during the billing months of October-May
$0.029615	per kWh for all Off-Peak kWh during the billing months of October-May

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

(Continued on Sheet No. D-61.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-60.00)

Monthly Rate: (Contd)

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

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: *$5.94* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: *$3.10* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: *$0.90* per kW of Maximum Demand

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

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-62.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-61.00)

Monthly Rate: (Contd)

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the billing month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 25 kW.

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Transmission On-Peak Billing Demand:

The Transmission On-Peak Billing Demand for each billing month shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

Resale Service Provision:

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 Volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly credit for the substation ownership shall be applied as follows:

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

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>
Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>
Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-63.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-62.00)

Monthly Rate: (Contd)

Aggregate Peak Demand Service Provision (GAP):

This provision is available to any customer with 7 accounts or more who desire to aggregate their On-Peak Billing Demands for power supply billing purposes. To be eligible, each account must have a minimum average On-Peak Billing Demand of 250 kW and be located within the same billing district. The customer's aggregated accounts shall be billed under the same rate schedule and service provisions. The aggregate maximum capacity of all customers served under this provision shall be limited to 200,000 kW.

This provision commences with service rendered on and after June 20, 2008 and remains in effect until terminated by a Commission Order.

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Interval Data Meters are required for service under this provision.

The aggregated accounts shall be summarized for each interval time period registered and a comparison shall be performed to determine the on-peak time at which the summarized value of the aggregated accounts reached a maximum for the billing month. The individual aggregated accounts shall be billed for their corresponding On-Peak Billing Demand occurring at that point in time.

Educational Institution Service Provision (GEI):

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Educational Institution Credit: $(0.000176) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-64.00)

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

Sixth Revised Sheet No. D-64.00
Cancels Fifth Revised Sheet No. D-64.00

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-63.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPD shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided, the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand

For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand

For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

(Continued on Sheet No. D-65.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-64.00)

Monthly Rate: (Contd)

Interruptible Service Provision (GI): (Contd)

Conditions of Interruption (Contd)

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

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

Interruptible Credit:	$(7.00)	per kW of On-Peak Billing Demand during the billing months of June-September
	$(6.00)	per kW of On-Peak Billing Demand during the billing months of October-May

Interruptible Service Provision – Market-Price Option (GI2):

Availability:

This provision is available to any Full Service GPD customer account willing to designate at least 3,000 kW of On-Peak Billing Demand as Defined Interruptible Capacity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* The Company reserves the right to limit the amount of designated interruptible load available to any single customer, but in no case shall it exceed 100,000 kW. The combined aggregate amount of monthly On-Peak Billing Demand subscribed under the GI and GI2 provisions shall be limited to 400,000 kW.

In the event the combined aggregate amount of monthly On-Peak Demand subscribed is less than the approved limit specified above, the Company may offer the remaining capacity, to otherwise eligible customers willing to designate less than the minimum amounts specified above.

The customer may choose to have the interruptible load separately metered. The customer shall bear any expense incurred by the Company in providing a separate service for the interruptible portion of an existing customer load. The customer must provide space suitable for the separate metering. Consumers Energy may require the Customer to monitor and provide real-time, Internet-enabled power monitoring. If such monitoring is required, Consumers Energy will provide the metering or monitoring devices necessary, which shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Contracted Firm Capacity and Defined Interruptible Capacity

Defined Interruptible Capacity shall be the amount of the customer's On-Peak Billing Demand at the time of the most recent annual MISO peak hour that exceeds the Customer's Firm Contract Capacity.

The minimum difference between the Customer's Contracted Firm Capacity and the Customer's On-Peak Billing Demand required to participate in the GI2 Provision is 3,000 kW and is subject to Company verification.

Customers shall contract for a specified capacity in kilowatts sufficient to meet the customers' maximum interruptible requirements, but not less than the minimum contract capacity amounts, specified above. The contract capacity shall not be decreased during the term of the contract and subsequent renewal periods as long as service is required unless there is a verified reduction in connected load. Capacity disconnected from service under this provision shall not be subsequently served under any other tariff during the term of this contract and subsequent renewal periods. The Customer must notify and contract with the Company by December 10th of each year of their desire to renew the GI2 provision and the amount of interruptible kW for the following capacity planning year (June 1 through May 31).

(Continued on Sheet No. D-66.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-65.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Contd)

Monthly Billing

For billing purposes, the Contracted Firm Capacity will be billed first on Rate GPD, with the load in excess of contracted firm being billed on the GI2 charges specified in this rate schedule.

Power Supply Charges - These charges are applicable to contracted interruptible capacity.

The customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh.

Charges for Customer Voltage Level 3 (CVL 3)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.037344*	per kWh for all kWh during the billing months of June-September
	$*0.034532*	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 2 (CVL 2)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.036398*	per kWh for all kWh during the billing months of June-September
	$*0.032629*	per kWh for all kWh during the billing months of October-May
Charges for Customer Voltage Level 1 (CVL 1)		
LMP Energy Charge:	MISO Real-Time LMP per kWh for all kWh	
Capacity & Transmission Charge:	$*0.032631*	per kWh for all kWh during the billing months of June-September
	$*0.029082*	per kWh for all kWh during the billing months of October-May

The MISO Real-Time LMP per kWh shall be adjusted for losses based on the customer's point of metering as shown below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992%*
Customer Voltage Level 2	*1.313%*	*2.239%*
Customer Voltage Level 3	*3.366%*	*6.948%*

Delivery Charges – These charges are applicable to contract capacity

Rate GPD Delivery Charges will apply to all Delivery service, including contracted capacity designated as GI2 interruptible service.

System Access Charge:

If contracted capacity is separately metered: $100.00 per additional meter installation per month

This provision is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10 as well as the System Access Charge, Delivery Charges, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge applicable to Rate GPD.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

(Continued on Sheet No. D-67.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-66.00)

Monthly Rate: (Contd)

Interruptible Service Provision – Market-Price Option (GI2) (Cont)

Conditions of Interruption

The Company will notify the customer as to the amount of total load on this rider to be curtailed. Load identified as monthly firm service and billed on Rate GPD is not considered as interruptible and does not need to be curtailed under the terms of GI2. Although actual load at time of interruption may vary from contract capacity, the total measured load on this provision shall be subject to curtailment by the Company.

The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity or have the total facility subject to interruption.

Any load designated as interruptible by the customer may require the installation and maintenance of equipment that allow the Company to remotely interrupt the customer's load. If the company determines it is required to install and maintain equipment at the customer's site to comply with any requirements associated with the GI service provision then it shall do so at the customer's expense. In addition, the customer shall also adhere to any advance notification requirements the Company deems are necessary to comply with its obligations to MISO under this provision.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide notice in advance of probable interruption, and if possible, a second notice of positive interruption. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the Customer of the obligation for interruption under the GI2 provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

(Continued on Sheet No. D-68.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-67.00)

Monthly Rate: (Contd)

Net Metering Program:

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Distributed Generation Program:

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

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

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

Non-Residential Electric Vehicle Programs:

The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

(Continued on Sheet No. D-69.00)

LARGE GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-68.00)

Monthly Rate: (Contd)

Self-Generation (SG):

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

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate, and applicable any non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

For customers with monthly demands of 300 kW or more, all service under this rate *may* require a written contract with a minimum term of one year.

For customers with monthly demands of less than 300 kW, service under this rate shall not require a written contract except for: (i) service under the Resale Service Provision, (ii) service under the Green Generation Program, (iii) service under the Educational Institution Service Provision, (iv) service under the Aggregate Peak Demand Service Provision, (v) service under the Interruptible Service Provision, (vi) *service under the Demand Response Program or (vii)* at the option of the Company. If a contract is deemed necessary by the Company, the appropriate contract form shall be used and the contract shall require a minimum term of one year.

A new contract will not be required for existing customers who increase their demand requirements after initiating service, unless new or additional facilities are required or service provisions deem it necessary.

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

Availability:

Subject to any restrictions, this General Service Primary Time-Of-Use (GPTU) Rate is available to any Full Service Customer taking service at the Company's Primary Voltage level. Standby service shall be provided on this rate for primary customers with solar installations equal to or greater than 150 kW.

This rate is not available for Standby service with generators that exceed 550kW, except for solar installations, nor available for lighting service, except for temporary service for lighting installations.

Nature of Service:

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

Where service is supplied at a normal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling, and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to *2:00* PM and *6:00* PM to 11:00 PM
Mid-Peak Hours:	*2:00* PM to *3:00* PM and 5:00 PM to *6:00* PM
High-Peak Hours:	*3:00* PM to 5:00 PM
Winter:	
Off-Peak Hours:	12:00 AM to *4:00* PM and *8:00* PM to 12:00 AM
Mid-Peak Hours:	*4:00* PM to *5:00* PM and 7:00 PM to *8:00* PM
High-Peak Hours:	*5:00* PM to 7:00 PM

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4 or December 25 fall on a Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-71.00)

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

Sixth Revised Sheet No. D-71.00
Cancels Fifth Revised Sheet No. D-71.00

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-70.00)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.067289*	*$0.003182*	*$0.070471*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.082596*	*$0.004711*	*$0.087307*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.108883*	*$0.005865*	*$0.114748*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.124771*	*$0.006144*	*$0.130915*	per kWh during the calendar months of June-September
Off-Peak -Winter	*$0.073740*	*$0.003391*	*$0.077131*	per kWh during the calendar months of October-May
Mid-Peak -Winter	*$0.082502*	*$0.003940*	*$0.086442*	per kWh during the calendar months of October-May
High-Peak -Winter	*$0.087588*	*$0.003941*	*$0.091529*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066492*	*$0.003133*	*$0.069625*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.081602*	*$0.004638*	*$0.086240*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.107579*	*$0.005775*	*$0.113354*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.123288*	*$0.006049*	*$0.129337*	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.072869*	*$0.003339*	*$0.076208*	per kWh during the calendar months of October-May
Mid-Peak - Winter	*$0.081524*	*$0.003879*	*$0.085403*	per kWh during the calendar months of October-May
High-Peak - Winter	*$0.086554*	*$0.003880*	*$0.090434*	per kWh during the calendar months of October-May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065692*	*$0.003088*	*$0.068780*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.080610*	*$0.004572*	*$0.085182*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.106276*	*$0.005692*	*$0.111968*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.121801*	*$0.005963*	*$0.127764*	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.071993*	*$0.003291*	*$0.075284*	per kWh during the calendar months of October-May
Mid-Peak - Winter	*$0.080542*	*$0.003824*	*$0.084366*	per kWh during the calendar months of October-May
High-Peak - Winter	*$0.085515*	*$0.003825*	*$0.089340*	per kWh during the calendar months of October-May

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

Delivery Charges:

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL3)		
Capacity Charge:	*$5.94*	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL2)		
Capacity Charge:	*$3.10*	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL1)		
Capacity Charge:	*$0.90*	per kW of Maximum Demand

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

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-72.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-71.00)

Monthly Rate (Contd)

Adjustment for Power Factor (Contd)

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Resale Service Provision

Subject to any restrictions, this provision is available to customers desiring Primary Voltage service for resale purposes in accordance with Rule C4.4, Resale.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

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

<u>Charges for Customer Voltage Level 2 (CVL 2)</u>
Substation Ownership Credit: $\$(0.73)$ per kW of Maximum Demand

<u>Charges for Customer Voltage Level 1 (CVL 1)</u>
Substation Ownership Credit: $\$(0.55)$ per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Educational Institution Service Provision (GEI)

When service is supplied to a school, college or university, a credit shall be applied during all billing months. As used in this provision, "school" shall mean buildings, facilities, playing fields, or property directly or indirectly used for school purposes for children in grades kindergarten through twelve, when provided by a public or nonpublic school. School does not include instruction provided in a private residence or proprietary trade, vocational, training, or occupational school. "College" or "University" shall mean buildings located on the same campus and used to impart instruction, including all adjacent and appurtenant buildings owned by the same customer which are located on the same campus and which constitute an integral part of such college or university facilities.

The monthly credit for the Educational Institution Service Provision shall be applied as follows:

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

Educational Institution Credit: $ (*0.000176*) per kWh for all kWh

Customers on this provision shall require a written contract, with a minimum term of one year, and shall be evaluated annually to determine whether or not the accounts shall remain on the service provision.

(Continued on Sheet No. D-72.10)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.00)

Monthly Rate (Contd)

Demand Response Program:

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

Interruptible Service Provision (GI):

This provision is available to any customer account willing to either (1) contract for at least 250 kW of On-Peak Billing Demand as interruptible or (2) contract for a service level of On-Peak Billing Demand that the customer account is willing to reduce to when the Company deems interruption is necessary to maintain system integrity. *A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.* For customers who participate in the Interruptible Service Provision (GI) on this Rate Schedule, the On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use within on-peak hours during the billing month as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates. For customers who are not enrolled in the GI provision, the On-Peak Billing Demand shall not apply.

The Company reserves the right to limit the amount of load contracted as interruptible, but in no case shall it exceed 300,000 kW per customer. Customers with multiple locations participating in the GI Provision may manage the locations jointly to meet the contracted interruptible commitment. Customers served under Rate GPTU shall have no more than 50% of their annual On-Peak Billing Demand contracted as interruptible when contracting for more than 50,000 kW of interruptible load. The aggregate amount of monthly On-Peak Billing Demand subscribed under this provision shall be limited to 400,000 kW.

Consumers Energy may provide the Customer equipment to provide real-time, Internet-enabled power monitoring. If such monitoring is provided the metering or monitoring devices shall be owned by Consumers Energy and provided to the Customer at the Company's expense. The Customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the Customer's site electricity consumption and interruption event performance.

Billing for Contracted Interruptible Demand – Reduce by Contracted On-Peak Billing Demand
For billing purposes, the monthly interruptible On-Peak Billing Demand shall be billed first and discounted under this interruptible service provision. The actual On-Peak Billing Demand for the interruptible load supplied shall be credited by the amount specified under the Power Supply Charges - Interruptible Credit listed below. Subsequently all firm service used during the billing period in excess of the contracted interruptible shall be billed at the appropriate firm rate.

Billing for Contracted Service Level – Reduce to Contracted On-Peak Billing Demand
For billing purposes, the contracted firm service level shall be billed first at the appropriate firm rate. Subsequently, the On-Peak Billing Demand determined to be interruptible, in excess of the contracted firm service level, shall be billed and discounted under this interruptible service provision.

(Continued on Sheet No. D-72.20)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.10)

Monthly Rate (Contd)

Interruptible Service Provision (GI): (Contd)

All contracts under this provision shall be negotiated on an annual basis for the following capacity planning year (June 1 through May 31) and the Customer must notify the Company by December 10th of each year of their desire to renew the GI Provision, unless the Customer chooses to lengthen the term of their commitment (up to five years). Annual changes to the amount of interruptible kW for long term contracts are open to adjustment through December 10th of each year. Within 30 minutes of receiving an interruption notice, the customer shall reduce their total load level by the amount of contracted interruptible capacity.

At the Company's discretion, the customer may adjust the contracted amount one time within the annual contract period.

Any load designated as interruptible by the customer is also subject to Midcontinent Independent System Operator's Inc. (MISO) requirements for Load Modifying Resources and the Company shall inform the Customer of such MISO requirements. Interruption under this provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedures or NERC Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared Emergency Status. Participation in the GI provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this provision, the customer shall be interrupted at any time, on-peak or off-peak, the Company deems it necessary to maintain system integrity. The Company shall provide the Customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. The notice will be communicated by telephone to the contact numbers provided by the Customer. The Customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption under the GI Provision. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall be made on an applicable firm power schedule.

Cost of Customer Non-Interruption

Failure by a customer to comply with a system integrity interruption order of the Company shall be considered as unauthorized use and billed at (i) the higher of the actual damages incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible On-Peak Billing demand created during the interruption period, in addition to the prescribed monthly rate. In addition, the interruptible contract capacity of a customer who does not interrupt within one hour following notice shall be immediately reduced by the amount which the customer failed to interrupt, unless the customer demonstrates that failure to interrupt was beyond its control.

The monthly credit for the Interruptible Service Provision shall be applied as follows:

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

Interruptible Credit:	*$(7.00)*	*per kW of On-Peak Billing Demand during the billing months of June-September*
	$(6.00)	*per kW of On-Peak Billing Demand during the billing months of October-May*

(Continued on Sheet No. D-73.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-72.20)

Self-Generation (SG)

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

Distributed Generation Program

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

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

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.
A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

Renewable Energy Credit (REC) Programs:

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

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

Non-Residential Electric Vehicle Programs:
The Non-Residential Electric Vehicle Programs are available to any eligible customer as described in Rule C19.2., Non-Residential Electric Vehicle Programs.

General Terms

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

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Service under this rate may require a written contract with a minimum term of one year. Service under this rate shall require a written contract for (i) service under the Educational Institution Service Provision, (ii) service under the Interruptible Service Provision, (iii) service under the Demand Response Program, or (iv) at the option of the Company.

ENERGY INTENSIVE PRIMARY RATE EIP

Availability

Subject to any restrictions, the Energy Intensive Primary Rate EIP is available to any Full Service electric metal melting customer taking service at the Company's Primary Voltage levels, where the electric load on this rate is utilized for industrial metal melting processes such as electric arc or induction furnaces or to any Full Service electric industrial customer who qualified as energy intensive as defined herein. For metal melting customers, only electric load that directly supports the process of melting metal using electricity as the main melting source qualifies as load to be served under this rate. Ancillary equipment required for the metal melting process is not intended to be served on this rate.

Existing or former metal melting customers taking service under the Company's Metal Melting Primary Pilot as of November 30, 2015 are eligible for service on Rate EIP. An additional 200 MW of Maximum Demand capacity will be available on a first-come, first-served basis to Full Service customers with new electric metal melting or energy intensive industrial load not previously served by the Company. To qualify as energy intensive load, the customer must demonstrate viable options to site the production outside of the state and the customer's incremental load must exceed 2 MW at a single site with an annual load factor that exceeds 70% or the customer's incremental load must exceed 15 MW with a minimum of 75% of their total consumption occurring during Off-Peak Hours. New electric metal melting load must be separately metered. The customer must provide a special circuit or circuits in order for the Company to install separate metering.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

Nature of Service

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

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

The Company may elect to install devices that can enable direct load management, power metering, data collection, near real-time data communication and internet based monitoring. There shall be no cost to the customer associated with the system equipment or installation of the system equipment. The Company reserves the right to remove the system equipment if the customer moves from Rate EIP to another primary rate.

For purposes of this rate, the appropriate measure of market price is the Real-Time LMP for the Company's retail aggregating node CONS.CETR established by the Midcontinent Independent System Operator Inc. (MISO).

(Continued on Sheet No. D-74.50)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.00)

Critical Peak Event Determination

A Critical Peak Event *occurs when* the market price *exceeds* an Economic Trigger Price or a *System Integrity Event* is enacted.

A System Integrity Event is enacted when MISO declares that a Maximum Generation Emergency Event has occurred and MISO has instructed the Company to implement Load Management Measures using Load Modifying Resources. The Company shall provide notice of a System Integrity Event by telephone to the contact numbers provided by the Customer. A System Integrity Event shall occur at any time for any duration. A Critical Peak Event caused by a System Integrity Event shall be billed at $1.00 per kWh during the duration of the event.

The Summer Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 3:00 PM to 5:00 PM for the period of June 1 through September 30 of the previous year. The Summer Economic Trigger Price will be set on January 30 of each year by the Company.

The Winter Economic Trigger Price is the greater of 150% of the High Peak Energy Charge, Customer Voltage Level 1 or the average market price during the hours of 5:00 PM to 7:00 PM for the period of October 1 through May 31 of the previous year. The Winter Economic Trigger Price will be set on July 31 of each year by the Company.

Energy Intensive Primary Rate customers will be notified after the Summer and Winter Economic Trigger Prices are set. The Company shall endeavor to provide notice in advance of a probable System Integrity Event.

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	All hours during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

(Continued on Sheet No. D-75.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-74.50)

Monthly Rate:

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL 3)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066902*	*$0.002547*	*$0.069449*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.088051*	*$0.003980*	*$0.092031*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.113410*	*$0.004840*	*$0.118250*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.128630*	*$0.004951*	*$0.133581*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.074119*	*$0.002771*	*$0.076890*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.085644*	*$0.003162*	*$0.088806*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.089524*	*$0.003205*	*$0.092729*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

Charges for Customer Voltage Level 2 (CVL 2)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.066114*	*$0.002508*	*$0.068622*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.086999*	*$0.003919*	*$0.090918*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.112061*	*$0.004765*	*$0.116826*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.127112*	*$0.004875*	*$0.131987*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.073246*	*$0.002728*	*$0.075974*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.084637*	*$0.003114*	*$0.087751*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.088472*	*$0.003155*	*$0.091627*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

(Continued on Sheet No. D-76.00)

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

Sixth Revised Sheet No. D-76.00
Cancels Fifth Revised Sheet No. D-76.00

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-75.00)

Monthly Rate (Contd):

Power Supply Charges:

Charges for Customer Voltage Level 1 (CVL 1)

Energy Charge:

	Non-Capacity	Capacity	Total	
Off-Peak-Summer	*$0.065320*	*$0.002472*	*$0.067792*	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.085947*	*$0.003863*	*$0.089810*	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.110710*	*$0.004697*	*$0.115407*	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.125587*	*$0.004805*	*$0.130392*	per kWh during the calendar months of June-September
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of June-September*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of June-September
Critical Peak-Summer Economic Event				the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September
Off-Peak-Winter	*$0.072368*	*$0.002689*	*$0.075057*	per kWh during the calendar months of May-October
Mid-Peak-Winter	*$0.083623*	*$0.003069*	*$0.086692*	per kWh during the calendar months of May-October
High-Peak-Winter	*$0.087414*	*$0.003110*	*$0.090524*	per kWh during the calendar months of May-October
Interruptible Credit	*$0.000000*	*$(0.011822)*	*$(0.011822)*	*per kWh during the calendar months of May-October*
Emergency Event	NA	$1.00	$1.00	per kWh for all kWh during a System Integrity Event during the calendar months of May-October
Critical Peak-Winter Economic Event				the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October-May

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

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL 3)
Capacity Charge: *$5.94* per kW of Maximum Demand

Charge for Customer Voltage Level 2 (CVL 2)
Capacity Charge: *$3.10* per kW of Maximum Demand

Charge for Customer Voltage Level 1 (CVL 1)
Capacity Charge: *$0.90* per kW of Maximum Demand

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

(Continued on Sheet No. D-77.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-76.00)

Monthly Rate (Contd):

Adjustment for Power Factor:

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months.

Interruptible Credit:

Due to the nature of this rate schedule, all customers on this rate schedule shall receive an Interruptible Credit per kWh for all consumption for each calendar month.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

Delivery Charges - These charges are applicable to Full Service and Retail Open Access Customers.

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

Self-Generation (SG):

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

(Continued on Sheet No. D-78.00)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-77.00)

Distributed Generation Program:

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

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

Green Generation Programs:

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

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

Renewable Energy Credit (REC) Programs:

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

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

General Terms:

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

Minimum Charge:

The System Access Charge included in the rate and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate *may* require a written contract with a minimum term of one year.

LARGE ECONOMIC DEVELOPMENT RATE LED

Availability:

At the Company's discretion, the Large Economic Development Rate is available to (1) new Full Service primary electric customers locating permanent operations within the Company's service territory or (2) existing Full Service primary customers expanding their permanent operations. *As of June 7, 2024, the Large Economic Development Rate is not available to data centers within the Company's service territory who have not already contracted for service under this rate.*

The minimum new or expanded incremental electric service required to contract under the Large Economic Development Rate is 35,000 kW. This rate requires a written contract specifying the terms of the electric service. Upon mutual agreement between the customer and the Company, up to 60 months from the *initial service date for billing purposes* may be granted for the customer to meet the *required 35,000 kW On-Peak Billing Demand.*

This rate is not available to a new customer resulting from a change in ownership of an existing establishment located within the Company's service area. However, if a change in ownership occurs after the customer contracts for service under this rate, the successor may be allowed to fulfill the remainder of the contract.

Customers taking service under the Large Economic Development Rate are ineligible for the terms of the Contribution in Aid of Construction Allowance Schedule located in Rule C1.4, Extraordinary Facility Requirements and Charges.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities served by the Company, for standby service, for new or expanded service for resale or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate.

Terms and Conditions:

This rate requires a contract term, the minimum term under this rate is fifteen (15) years from the date initial service is provided under this rate. *The maximum contract term under this rate shall not exceed twenty (20) years from the initial service date for billing purposes.*

If the customer ceases operation before completion of the contract term, the customer shall pay the remaining balance for any transmission and distribution system investments specified in the contract to provide service to the customer according to the following schedule:

Up to 50% of the contract term	100%
More than 50 to 60% of the contract term	83%
More than 60 to 70% of the contract term	67%
More than 70 to 80% of the contract term	50%
More than 80 to 90% of the contract term	33%
More than 90% to 99.9% of the contract term	17%

For existing customers expanding their operations, the Company will install, operate, and maintain the metering equipment necessary to measure the incremental load to be billed under this rate. The customer will provide the Company with access to its metering equipment. The Company is not obligated to extend, expand, or rearrange its facilities if it determines the existing facilities are adequate to serve the customer's load.

(Continued on Sheet D-78.20)

Attachment J

MPSC Case No. U-21775, Consumers Energy's Capacity Demonstration Filing (part 4)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Where voltage is supplied at a nominal voltage of 25,000 volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, from the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered production capacity, transmission capacity and energy to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission as reflected in the Monthly Rate.

Monthly Rate:

System Contribution Charge: $0.000284 per kWh for all kWh

Power Supply Charges:

Production Charge:		
Customer Voltage Level 1	*$10.94*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	*$11.09*	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	*$11.26*	per kW of On-Peak Billing Demand for all calendar months

Effective for contracts dated on and after June 7, 2024, the monthly Production Charge is the Cost of New Entry for MISO's Local Resource Zone 7 ("CONE"), as of the time of contract execution. The monthly Production Charge is fixed for the contract term at the rate in effect at the time of contract execution, unless the customer fails to meet the minimum On-Peak Billing Demand required by the Company. Effective for contracts dated on or before June 7, 2024, customers shall pay the monthly Production Charge which was in effect at the time of contract execution.

Transmission Charge:		
Customer Voltage Level 1	$1.59	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 2	$1.62	per kW of On-Peak Billing Demand for all calendar months
Customer Voltage Level 3	$1.64	per kW of On-Peak Billing Demand for all calendar months

The monthly Transmission Charge is based on the incremental transmission charges applicable with the load served under this tariff and shall be adjusted and reconciled on an annual basis in the Company's PSCR proceedings.

Energy Charge: For all energy supplied by the Company, the customer shall be responsible for either the MISO Real-Time or Day Ahead Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh). Customers also enrolled in the Voluntary Large Customer Renewable Program LC-REP (LC-REP) may choose, at the Company's discretion, to have the billing of energy under this Rate Schedule match with the crediting methodology of energy under the LC-REP Program for administrative purposes.

<u>Line losses applied to Energy Charge</u>	
Voltage Level 1	*3.23%*
Voltage Level 2	*4.68%*
Voltage Level 3	*6.27%*

(Continued on Sheet No. D-78.30)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.20)

Monthly Rate: (Contd)

Delivery Charges:

Distribution Charges:

Customer Voltage Level 1:	$0.90	per kW of Maximum Demand
Customer Voltage Level 2:	$3.10	per kW of Maximum Demand
Customer Voltage Level 3:	$5.94	per kW of Maximum Demand

The Distribution Charges for the Large Economic Development Rate are equivalent to the Distribution Charges for Large General Service Primary Demand Rate GPD. The monthly charge per kW of Maximum Demand per calendar month may be adjusted to contribute to the recovery of the annual revenue requirement associated with investments made by the Company for incremental distribution facilities required to serve the customer and specified in the contract for electric service.

Substation Ownership Credit:

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all the necessary transforming, controlling and protective equipment for all the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the Maximum Demand.

The monthly substation ownership credit shall be applied as follows:

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

Charges for Customer Voltage Level 2 (CVL 2)
Substation Ownership Credit: $(0.73) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)
Substation Ownership Credit: $(0.55) per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Securitization Charges shown on Sheet Nos. D-7.00 and D-7.10. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00.

Interruptible Service Provision

The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Production Capacity Charge specified in the Large Economic Development Rate.

A customer participating in this provision is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule or require testing to demonstrate the customer's ability to meet the contracted Interruptible Service Capacity.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and the Company shall inform the customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO declares a Maximum Generation Emergency Event that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-78.40)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.30)

Interruptible Service Provision: (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Maximum Demand:

The Maximum Demand shall be the highest 15-minute demand created during the current month or previous 11 months. *The contract for service under this rate shall specify the customer's projected Maximum Demand.*

On-Peak Billing Demand:

The On-Peak Billing Demand shall be based on the highest on-peak demand created during the calendar month, but never less than 60% of the highest on-peak billing demand of the four preceding summer billing months (June through September), nor less than 35,000 kW. *Upon mutual agreement between the customer and the Company, up to 60 months from the initial service date for billing purposes may be granted for the customer to meet the 35,000 kW On-Peak Billing Demand required to be eligible for this rate.*

The On-Peak Billing Demand shall be the Kilowatts (kW) supplied during the 15-minute period of maximum use during on-peak hours, as described in Rule C14., Provisions Governing the Application of On-Peak and Off-Peak Rates.

The Company reserves the right to make special determination of the On-Peak Billing Demand, and/or the Minimum Charge, should the equipment which creates momentary high demands be included in the customer's installation.

Renewable Energy Credit (REC) Programs:

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

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

(Continued on Sheet No. D-78.50)

LARGE ECONOMIC DEVELOPMENT RATE LED

(Continued From Sheet No. D-78.40)

Monthly Rate: (Contd)

General Terms:

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

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the sum of monthly Capacity Charges and any applicable non-consumption based Surcharges.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Form of Contract *and Authority to Require a Minimum On-Peak Billing Demand by Date Certain*:

Service under this rate shall require a written agreement *between the customer and the Company. The Company may require the customer to meet a minimum On-Peak Billing Demand (in addition to the 35,000 kW required to be eligible for this rate) by a date certain, which shall not exceed the customer's projected Maximum Demand specified in the contract. If the customer fails to meet the minimum On-Peak Billing Demand requirement required by its contract for service under this rate, the customer's Production Charge will be reset at the CONE as of the date certain and annually thereafter for the term of the contract, until the customer meets the required minimum On-Peak Billing Demand, after which the Production Charge will be fixed for the remaining term of the contract.*

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM AR

Availability:

Subject to any restrictions and requirements of Rule C10.3, an individual or entity who is a delivery customer of the Company that generates electricity from a solar energy system owned by the customer and constructed using Michigan workforce labor, or using equipment made in the state of Michigan is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge: Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company

Sales of Energy to the Company that begin service no later than December 31, 2009:

$0.650 per kWh purchased by the Company payable to a Residential customer
$0.450 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after December 31, 2009 but no later than October 1, 2011:

$0.525 per kWh purchased by the Company, payable to a Residential customer
$0.375 per kWh purchased by the Company, payable to a Non-Residential customer

Sales of Energy to the Company that begin service after October 1, 2011:

Price set contractually, in accordance with conditions specified in Rule C10.3.

Purchases of Energy from the Company for generator station power:

For all energy supplied by the Company, the charges shall be as provided for under the Residential Service *Secondary Non-Transmitting Meter* Rate *RSM* Rate Schedule for residential customers or the General Service Secondary Rate GS Rate Schedule, for all per kWh charges only, including additional charges such as, but not limited to, applicable surcharges, Power Plant Securitization Charges and Power Supply Cost Recovery (PSCR) Factor.

General Terms:

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

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract with a minimum term of one year and a maximum term of 15 years; however, no contract term may extend beyond August 31, 2029.

EXPERIMENTAL ADVANCED RENEWABLE PROGRAM - ANAEROBIC DIGESTION PROGRAM (AD Program)

Availability:

Subject to any restrictions and requirements of Rule C10.4, an individual or entity who is a delivery customer of the Company that generates electricity from an anaerobic digestion system owned or leased by the customer is eligible to sell power to the Company under the terms set forth in this schedule.

Monthly Rate:

System Access Charge:

Equal to the System Access Charge of the Customer's Delivery Account but not in excess of $50, assessed per generator meter, to be paid to the Company by the customer or to be deducted from the payment to the customer by the Company.

Option 1 - Sales of Energy to the Company:

$86.00 per MWh purchased by the Company payable to the customer

Option 2 - Sales of Energy to the Company:

Beginning in the year the system comes on line with an escalating payment each year for the length of the contract ($/MWh purchased by the Company payable to the customer):

2015 - $76.39	2021 - $82.12	2027 - $90.33	2033 - $98.79
2016 - 77.17	2022 - 84.08	2028 - 91.62	2034 - 100.27
2017 - 77.33	2023 - 85.39	2029 - 93.13	2035 - 101.77
2018 - 78.49	2024 - 86.53	2030 - 94.51	2036 - 103.29
2019 - 79.88	2025 - 87.75	2031 - 95.91	2037 - 104.83
2020 - 81.23	2026 - 88.99	2032 - 97.34	2038 - 106.39

Purchase of Energy from the Company for standby service:

Energy supplied to the customer by the Company shall be provided at the applicable full service standby rate for which the customer qualifies subject to applicable surcharges, Securitization Charges, Power Supply Cost Recovery (PSCR) Factor and other charges as approved by the Commission.

General Terms:

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

Payment of Energy Purchases:

The Company reserves the right to transfer amounts due to the Company or the customer under this schedule to an active account for energy purchases from the Company.

Term and Form of Contract:

Sales of energy to the Company under this schedule shall require a written contract. Customers choosing Option 1 for sales of energy to the Company shall require a 20 year contract term. Customers choosing Option 2 shall require a contract with a 10 year minimum term and a 20 year maximum term.

GENERAL SERVICE SELF GENERATION RATE GSG-2

Availability

Subject to any restrictions, this rate is available to any Full Service Customer with a generating installation with a combined onsite nameplate capacity greater than 550 kW, which may employ cogeneration or small power production technology. A customer who meets the Federal Energy Regulatory Commission's (FERC) criteria for a Qualifying Facility may elect to take standby service under this rate and may elect to sell energy to the Company. The Company has the right to refuse to contract for the purchase of energy, should it be determined to adversely impact economic or reliable operation of the Company's electric system. An eligible customer may elect to take service under this General Service Self Generation Rate GSG-2 or under Rule C11., Net Metering Program.

"Standby" service is defined as that electric service used in place of the customer's generation other than Company supplied firm service.

"Standby Capacity" is defined as the contracted kW capacity the Company is expected to provide to the customer on an occasional basis due to outages of the customer's generating unit(s). The Standby Capacity shall not exceed the generator's capability as designated in the interconnection agreement and as determined by the Company.

"Standby Demand" is defined as the greater of the (i) highest 15 minute kW demand the Company supplies the customer for Standby Service during the current month or (ii) highest Standby Demand from the previous 11 months. The Company shall determine the amount of monthly Standby Demand supplied to the customer based upon the total amount of power supplied to the customer, their contract Standby Capacity and generator output.

The Company shall not be required to supply standby power to the customer in excess of their contracted Standby Capacity. However, the Company may, at the written request of the customer made at least thirty days in advance, permit an increase in Standby Capacity provided the Company has facilities and generating capacity available.

Self-generation customers who require Company delivery service for any portion of the load that has been self-generated will be charged as described under the Delivery Standby Charges as shown on this Rate Schedule for the service provided and charged for any Power Supply provided by the Company as described under Power Supply Standby Charges on this Rate Schedule.

This rate is not available to Retail Open Access.

Nature of Service

All facilities operated in parallel with the Company's system must meet the Parallel Operation Requirements set forth in Rule C1.6 B., Parallel Operation Requirements. The Company shall own, operate and maintain all metering and auxiliary devices (including telecommunication links) at the customer's expense. Meters furnished, installed and maintained by the Company shall meter all generation equipment. No refund shall be made for any customer contribution required under this Rate Schedule.

Interval Data Meters are required on all generators. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data/billing determinants necessary for billing.

Energy delivered to the Company shall be alternating current, 60-Hertz, single-phase or three-phase (as governed by Rule B8., Interconnection and *Distributed Generation* Standards) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company may discontinue purchases during system emergencies, maintenance and other operational circumstances.

Where service is supplied at a nominal voltage of 25,000 Volts or less but equal to or greater than 2,400 Volts, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

(Continued on Sheet No. D-82.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-81.00)

Nature of Service (Contd)

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage above 25,000 volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where service is supplied at a nominal voltage equal to or greater than 2,400 volts and the Company elects to measure the service at a nominal voltage of less than 2,400 volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Where service is supplied at a nominal voltage less than 2,400 volts and the Company elects to measure the service at a nominal voltage equal to or greater than 2,400 volts, 3% shall be deducted for billing purposes from the energy measurements thus made.

There shall be no double billing of demand under the base rate and Rate GSG-2.

Monthly Rate

Standby Charges

Power Supply Standby Charges

For all standby energy supplied by the Company, the customer shall be responsible for the MISO Real-Time Locational Market Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule), multiplied by the customer's consumption (kWh), plus the Market Settlement Fee of $0.002/kWh. In addition capacity charges will be assessed monthly, calculated using the highest 15 minute kW demand associated with Standby Service occurring during the Company's On-Peak billing hours will be multiplied by the highest contracted capacity purchased by the Company in that month, plus allocated transmission and ancillaries. The capacity charges will be prorated based on the number of On-Peak days that Standby Service was used during the billing month.

A customer with a generator(s) nameplate rating more than 550 kW must provide written notice to the Company by December 1 if they desire standby service in the succeeding calendar months of June through September. Written notice shall be submitted on Company Form 500.

Real Power Losses

Real Power Losses shall be measured based on the transmission loss factor of *2.01*% plus the associated meter point as listed below:

	Meter Point	
	High Side	Low Side
Customer Voltage Level 1	0.000%	*0.992*%
Customer Voltage Level 2	*1.313*%	*2.239*%
Customer Voltage Level 3	*3.366*%	*6.948*%

Delivery Standby Charges

System Access Charge: $100.00 per generator installation per month

Charges for Customer Voltage Level 3 (CVL 3)

Capacity Charge: $*5.94* per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL 2)

Capacity Charge: $*3.10* per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Capacity Charge: $*0.90* per kW of Maximum Demand

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

(Continued on Sheet No. D-83.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-82.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar -hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	Penalty
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700.Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15%penalty applies again.

Substation Ownership Credit

Where service is supplied at a nominal voltage of more than 25,000 volts, energy is measured through an Interval Data Meter, and the customer provides all of the necessary transforming, controlling and protective equipment for all of the service there shall be deducted from the bill a monthly credit. For those customers, part of whose load is served through customer-owned equipment, the credit shall be based on the billed Standby Demand.

The monthly credit for the substation ownership shall be applied as follows:

Delivery Charges

Charges for Customer Voltage Level 2 (CVL 2)

Substation Ownership Credit: $(*0.73*) per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL 1)

Substation Ownership Credit: $(*0.55*) per kW of Maximum Demand

For those customers served by more than one substation where one or more of the substations is owned by the customer, the credit will be applied to the customer's coincident Maximum Demand for those substations owned by the customer. This credit shall not operate to reduce the customer's billing below the prescribed minimum charges included in the rate. The credit shall be based on the kW after the 1% deduction or 3% addition has been applied to the metered kW.

(Continued on Sheet No. D-83.10)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. D-83.00)

Monthly Rate (Contd)

Standby Charges (Contd)

Transmission Interconnect Credit

Where standby service is provided to a non-utility electric generator located within the Company's service territory and taking power through its transmission interconnect, where the Company has no owned infrastructure other than metering, including billing grade current transformers and potential transformers, telemetry facilities and associated wiring, the following monthly credit shall be applied to the bill:

Delivery Charges

Transmission Interconnect Credit:	$ (0.90)	per kW of Maximum Demand

This credit shall be based on the kW after the 1% deduction has been applied to the metered kW. The credit supersedes any applicable substation ownership credit.

Sales of Energy to the Company

Administrative Cost Charge

Generation installation with a capacity of over 550 kW but less than or equal to 2,000 kW
As negotiated or $0.0010 per kWh purchased, at the option of the customer

Generation installation with a capacity of over 2,000 kW
As negotiated

Energy Purchase:

An energy purchase by the Company shall be bought at the Midcontinent Independent System Operator's Inc. (MISO) real-time Locational Marginal Price (LMP) for the Company's load node (designated as "CONS.CETR" as of the date of this Rate Schedule).

Demand Response Program

Customers participating in the voluntary Demand Response Program help reduce peak demand when energy use is the highest. A customer specific agreement stating the customer's Contracted Capacity kW shall be completed prior to participation in the Demand Response Program. Customer eligibility to participate in this program is determined solely by the Company. The Company reserves the right to specify the term or duration of the program. *A customer participating in this program is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.*

Under this program, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this program must be supported by an updated energy reduction plan on an annual basis.

Demand Response Program customers shall receive an annual Program Payment on the customer bill or a check for the capacity amount delivered during events specified in the customer specific agreement within three billing cycles after the program season ends. Eligible customers may also receive Emergency Event Performance Payments on the customer bill under specific circumstances as outlined in the customer specific agreement. If a customer fails to deliver their total Contracted Capacity during an Emergency Event ordered by Consumers Energy, an Underperformance Penalty may be applicable. Any applicable penalties or program incentives shall be applied to the customer bill. As a condition of enrollment, Customers will be required to provide energy reduction plans that detail their load reduction procedure as specified in the agreement. Customers will be required to provide event notification contacts that support the program. The program agreement will specify the terms of the program that include program duration, number and length of events, performance calculations and program rules.

(Continued on Sheet No. D-84.00)

GENERAL SERVICE SELF GENERATION RATE GSG-2

(Continued From Sheet No. *D-83.10*)

Monthly Rate (Contd)

General Terms

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

Green Generation Program

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

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

Renewable Energy Credit (REC) Programs:

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

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

Minimum Charge

The System Access Charge included in this Rate Schedule in addition to the customer's contracted Standby Capacity multiplied by the net of any Substation Ownership Credit and Delivery Capacity Charges of this Rate Schedule.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract

Standby service and/or sales of energy to the Company under this rate shall require a written contract with a minimum term of one year. *Service under the Demand Response Program shall require a contract.*

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

Availability:

Subject to any restrictions, the Long Term Industrial Load Retention Rate ("LTILRR") is available to any industrial Full Service Customer taking electric service at the Company's Primary Voltage levels that, at the time the rate contract is executed 1) has an Average Demand of at least 200,000 kW at a single site, and 2) has a minimum Annual Load Factor of 75%. Customers must execute a long-term rate contract under this Rate Schedule for a minimum of 100,000 kW of Firm Contracted Capacity, and for service at a site where the Average Demand is at least 200,000 kW at the time the rate contract is executed. Customers must enter into a contract for a term, equal to: i) the term of the designated power purchase agreement or agreements, which in no case shall be for less than 15 years for one or more designated power supply resource if the resource is a power purchase agreement or agreements, or ii) the expected remaining life of one or more designated utility-owned power supply resources.

A customer taking electric service on this rate is not eligible to participate in Demand Response programs with an Aggregator of Retail Customers during any MISO season.

A corporate officer of the customer taking service under this rate must submit a sworn affidavit stating that the customer would no longer purchase standard tariff service from the electric utility absent the customer being able to purchase power supply under the LTILRR.

Service under this rate is not available for intrastate facility consolidation or relocation of the customer's existing facilities, for standby service, for new or expanded service for resale or new customers or for expanded service for the benefit of parties other than the customer. Electric service provided under this Rate Schedule may not be transported off the customer's Site. A single customer shall not aggregate load from multiple sites to meet the requirements under this rate, and multiple customers shall not aggregate load to meet the requirements under this rate.

A customer shall be considered an industrial customer if the customer's operation meets the qualifications as determined by the NAICS as defined by the Energy Information Administration.

The rate contract shall require a written agreement approved by the Michigan Public Service Commission ("Commission"), specifying the terms of the electric service and shall include creditworthiness requirements to the Company's satisfaction.

Contracted Capacity and Annual Nominations:

The Maximum Contracted Capacity available to any customer under this Rate Schedule shall be specified in a written agreement approved by the Commission. The customer must nominate annually, at the time the agreement is executed, and subsequently at least eight months before the start of the subsequent Midcontinent Independent System Operator, Inc. ("MISO") Planning Year, the amount of Annual Forecast Capacity, which shall be based on the customer's highest expected Maximum Monthly Demand adjusted for known and verifiable changes. The Annual Forecast Capacity shall not exceed the Maximum Contracted Capacity. If the customer's Maximum Monthly Demand in any month exceeds the Annual Forecast Capacity for the current Planning Year, the Annual Forecast Capacity shall be increased to the Maximum Monthly Demand, up to the Maximum Contracted Capacity, and customer shall be billed for the increase in Annual Forecast Capacity for the entire current MISO Planning Year.

The difference between the Annual Forecast Capacity and the Maximum Contracted Capacity shall be the Reserved Capacity. The Reserved Capacity shall be made available to the customer for load growth as specified in the customer's written agreement for electric service.

At the time the agreement is executed, and no later than eight months prior to the start of each subsequent MISO Planning Year, the customer must specify the level of Firm Contracted Capacity, which shall not exceed the Annual Forecast Capacity. The difference between the Annual Forecast Capacity and the Firm Contracted Capacity shall be Interruptible Service Capacity, which shall be subject to the Interruptible Service Provision as specified in this Rate Schedule.

(Continued on Sheet D-84.20)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.10)

Nature of Service:

Service under the rate shall be alternating current, 60-Hertz, three-phase Primary Voltage service. The particular nature of the voltage service provided to the customer shall be specified in a written agreement.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic measuring equipment available to provide the Company with the metering data necessary for billing purposes.

Line losses shall be applied to the customer's monthly metered energy and capacity values to reflect the energy consumed in moving electric power through the Transmission system and the Company's distribution system to the customer's point of delivery as determined by the Company and approved by the Commission.

Monthly Rate:

System Access Charge:	*Fixed charge per billing month as specified in the customer's written agreement for electric service*

Power Supply Charges:

Capacity Charge:	*$ per kW per month for contracted Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Reserved Capacity Charge:	*$ per kW per month for the difference between the Maximum Contract Capacity and the Annual Forecast Capacity as specified in the customer's written agreement for electric service*
Excess Capacity Charge:	*$ per kW per month for Maximum Monthly Demand in excess of the Maximum Contracted Capacity based on the Power Supply Demand Charges (for Capacity and Non-Capacity) per the Large General Service Primary Demand Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level*
Interruptible Credit:	*Equivalent to the Commission-approved $ per kW per month Rate GPD Interruptible Service Provision (GI) Interruptible Credit, applied to Interruptible Service Capacity, not to exceed the Capacity Charge*
Energy Charge:	*The monthly energy charges shall be based on the designated power supply resource's actual variable fuel and variable operations and maintenance expense, or the displacement costs of such expense, as applicable, associated with the customer's actual energy consumption as specified in the customer's written agreement for electric service*

(Continued on Sheet No. D-84.30)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.20)

Power Supply Charges: (Contd)

Excess Energy Charge:	$ per kWh for energy used in excess of the Maximum Contracted Capacity based on the Power Supply Energy Charges per the Rate GPD Rate Schedule at the customer's applicable Customer Voltage Level, including the applicable non-transmission PSCR Factor charges

Transmission Charges:

Transmission Charge:	Monthly charge per billing month based on the Company's costs to acquire transmission service to serve the customer's load as specified in the customer's written agreement for electric service

Delivery Charges:

Distribution Charges:	Monthly charge per billing month based on the dedicated distribution facilities in place to serve the customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and Securitization Charges shown on Sheet No. D-7.00. This rate is not subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-6.00

Interruptible Service Provision

The monthly credit under this Interruptible Service Provision shall be set by the Commission and shall be equivalent to the credit provided to customers receiving an Interruptible Credit under the Large General Service Primary Demand Rate GPD, Interruptible Service Provision (GI). The monthly credit available to the customer under this Interruptible Service Provision shall not exceed the Monthly Capacity Charge specified in the customer's written agreement for electric service.

The Company reserves the right to limit the amount of load contracted as Interruptible Service Capacity under this rate schedule, but in no case shall it exceed 300,000 kW.

Customers contracting for interruptible service under this rate schedule shall be required to monitor and provide real-time, Internet-enabled power monitoring. The Company will provide the metering or monitoring devices necessary, which shall be owned by the Company and provided to the customer at the Company's expense. The customer may be required to provide suitable space for such monitoring equipment and either a static or non-static, as applicable, Internet Protocol (IP) address and Local Area Network (LAN) access that allows for Internet-based communication of the customer's site electricity consumption and interruption event performance.

The interruptible load is subject to the MISO Load Modifying Resource requirements. Within 30 minutes of receiving an interruption notice from the Company, the customer shall reduce its total load level down to the Firm Contracted Capacity level or as required by the MISO partial curtailment request.

Any load designated as interruptible is subject to MISO requirements for Load Modifying Resources and Company shall inform customer of such MISO requirements. Interruption under this Interruptible Service Provision may occur if MISO *declares* a Maximum Generation Emergency Event *that requires deployment of Load Modifying Resources in accordance with the currently effective MISO Emergency Electrical Procedure* or North American Electric Reliability Corporation Emergency Event Alert 2 notice indicating that MISO is experiencing or expects to experience a shortage of economic resources and the Company has declared emergency status. Participation in the Interruptible Service Provision does not limit the Company's ability to implement emergency electrical procedures as described in the Company's Electric Rate Book including interruption of service as required to maintain system integrity.

(Continued on Sheet No. D-84.40)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.30)

Interruptible Service Provision (Contd)

Annual Power Test Requirement

Under this provision, the customer shall provide a documented energy reduction plan. The energy reduction plan shall serve as the representation of the customer's annual simulated power test in compliance with the Commission Order issued October 29, 2020 in Case No. U-20628. Any changes to the customer's contracted capacity under this provision must be supported by an updated energy reduction plan on an annual basis.

Conditions of Interruption

Under this Interruptible Service Provision, the customer shall be interrupted at any time MISO deems it necessary to maintain system integrity. The Company shall endeavor to provide notice to the customer in advance of probable interruption by MISO. The Company shall provide the customer at least thirty minutes advance notice of a required interruption, and if possible, a second notice. Notices will be communicated by telephone to the contact numbers provided by the customer. The customer shall confirm the receipt of such notice through the automated response process. Failure to acknowledge receipt of such notice shall not relieve the customer of the obligation for interruption. The customer shall be informed, when possible, of the estimated duration of the interruption at the time of interruption.

The Company shall not be liable for any loss or damage caused by or resulting from any interruption of service under this Interruptible Service Provision.

Interruptions beyond the Company's control, described in Rules C1.1, Character of Service, and C3, Emergency Electrical Procedures, of the Company's Electric Rate Book, shall not be considered as interruptions for purposes of this Interruptible Service Provision.

Should the Company be ordered by Governmental authority during a national emergency to supply firm instead of interruptible service, billing shall reflect firm service capacity as provided under this rate schedule.

Cost of Non-Compliance with Interruption

Failure by customer to comply with an interruption order under this Interruptible Service Provision shall be considered as unauthorized use and billed at (i) the higher of the customer's pro rata share of any actual MISO penalties incurred by the Company or (ii) the rate of $25.00 per kW for the highest 15-minute kW of Interruptible Peak Billing Demand created during the interruption period in excess of the Firm Contracted Capacity or the partial curtailment requested amount, in addition to the prescribed monthly rate.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor.

A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, the 15% penalty shall apply again if the Power Factor falls below 0.700 for two consecutive months.

General Terms:

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

(Continued on Sheet No. D-84.50)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.40)

Monthly Minimum Charge:

The Monthly Minimum Charge shall be the lower of the total amount due on the invoice or the sum of (i) the System Access Charge, (ii) the Distribution Charge, (iii) the monthly Capacity Charge, (iv) the monthly Reserved Capacity Charge, (v) any applicable non-consumption-based Surcharges, plus (vi) the monthly Interruptible Credit.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Term and Form of Contract:

Service under this rate shall require a written agreement, approved by the Commission. Customers served under this Rate Schedule must contract for a minimum of 100,000 kW of Firm Contracted Capacity.

Definitions Applicable to the Long Term Industrial Load Retention Rate:

Annual Forecast Capacity
Annual Forecast Capacity is the higher of the customer's maximum forecasted amount of electric capacity nominated, or actual Maximum Monthly Demand used, by the customer during the MISO Planning Year beginning June 1 and ending May 31 of the following calendar year, subject to the limitations and adjustments as specified in the customer's written agreement.

Annual Load Factor
Annual Load Factor shall be calculated as an average of the prior 12 monthly load factors. Each monthly load factor shall be determined by dividing the customer's actual monthly kWh sales by the product of the customer's Maximum Monthly Demand times the number of hours in the month.

Average Demand
Shall mean the average of the most recent 12 monthly site Maximum Monthly Demands.

Capacity Charge
The Capacity Charge shall be the Company's levelized cost of capacity, including fixed operation and maintenance expense, associated with the designated power supply resource at the time the customer's agreement for electric service is executed, or the Company's cost of capacity, including fixed operation and maintenance expense, associated with a designated power purchase agreement or agreements.

Energy Charge
The Energy Charge shall be the Company's actual variable fuel and actual variable operation and maintenance expense based on the customer's actual energy consumption and associated with the designated power supply resource, or the Company's actual energy and capacity purchases, if any, based on the customer's actual consumption, as applicable.

Excess Capacity
The Excess Capacity is the customer's actual Maximum Monthly Demand in excess of the Maximum Contracted Capacity in any billing month.

(Continued on Sheet No. D-84.60)

LONG TERM INDUSTRIAL LOAD RETENTION RATE – LTILRR

(Continued From Sheet No. D-84.50)

Definitions Applicable to the Long Term Industrial Load Retention Rate: (Contd)

Firm Contracted Capacity

The amount of electric capacity of at least 100,000 kW and not more than the Annual Forecast Capacity that the Company will supply to qualifying customers as specified in a written agreement that is not subject to the Interruptible Service Provision.

Interruptible Peak Billing Demand

The highest measured 15-minute interval demand in excess of the Firm Contracted Capacity that is consumed by the customer during an interruption event.

Interruptible Service Capacity

Interruptible Service Capacity is the difference between the Annual Forecast Capacity and the Firm Contracted Capacity which shall be subject to interruption per the Long Term Industrial Load Retention Rate Interruptible Service Provision.

Interval Data Meters

Interval Data Meters are meters that register customer kilowatt-hour use, peak demand, on-peak demand, and Maximum Monthly Demand.

Maximum Contracted Capacity

The maximum amount of electric capacity eligible for purchase by eligible customer under this Rate Schedule for the term of a written agreement.

Maximum Monthly Demand

The Maximum Monthly Demand shall be the highest 15-minute demand created by customer during the billing month.

MISO Planning Year

MISO Planning Year means a period extending from June 1st of a calendar year to May 31st of the following calendar year.

Reserved Capacity

The difference between the Maximum Contracted Capacity and the Annual Forecast Capacity held in reserve for future customer growth during the term of the customer's written agreement for electric service under the LTILRR

Site

An industrial site or contiguous industrial site or single commercial establishment as specified in the written agreement for electric service pursuant to the LTILRR. A site that is divided by an inland body of water or by a public highway, road, or street but that otherwise meets this definition meets the contiguous requirements.

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

Fifth Revised Sheet No. D-85.00
Cancels Fourth Revised Sheet No. D-85.00

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.062471*	$0.000000	$*0.062471*	per kWh for all kWh

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

(Continued on Sheet No. D-86.00)

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

Effective for service rendered on
and after March 15, 2024

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

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-85.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	*$0.082650*	per kWh for all kWh

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

Primary Power Supply Charge

Energy Charge:

Non-Capacity	Capacity	Total	
$0.030658	$0.000000	*$0.030658*	per kWh for all kWh

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

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	*$0.062986*	per kWh for all kWh

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

Net Metering Program

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

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11.2., Net Metering Program.

Green Generation Program

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

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

Renewable Energy Credit (REC) Programs:

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

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

(Continued on Sheet No. D-87.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-86.00)

Monthly Rate (Contd)

General Terms

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

Minimum Charge

The System Access Charge included in the rate, and any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Hours of Lighting

Metered Lights shall be controlled to burn only when the natural general level of illumination is lower than about 3/4 footcandle. Under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For dusk to midnight service, luminaires shall be controlled to turn off anytime between 11:00 PM, Eastern standard time, and dawn. The turnoff time within a given municipality shall be the same at all locations.

Term and Form of Contract

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for (i) unmetered lighting service where the Company has existing distribution lines available for supplying energy for such service or (ii) for any Company-owned system consisting of one or more luminaires. This rate is also available to existing farm or Non-Residential customers previously served under General Service Outdoor Lighting Rate L-4, but closed to new business.

New installations under this rate require approval by the Company of the proposed design and type of any customer equipment. In the event that the Company does not approve the design, the Company may require the customer to be served under a general service metered rate provision.

This rate is not available for resale purposes or for Retail Open Access Service. Only streetlighting types referenced within this rate schedule may receive unmetered service. Other types of streetlighting are excluded from service under this Rate Schedule.

Changes in the federal or state law have limited or eliminated the manufacture or importing of supplies needed to maintain some types of existing lighting offered under this Rate Schedule. To the extent that the Company has the necessary materials, the Company will continue to maintain existing mercury vapor lamp installations in accordance with this Electric Rate Schedule.

Nature of Service:

Customer-Owned

In systems where the Company has existing distribution lines available for supplying energy for unmetered lighting service, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and own the rest of the equipment comprising the unmetered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. All of the customer's equipment shall be subject to the Company's approval. The Company shall connect the customer's equipment to the Company's lines, supply the energy, control the burning hours of the lamps, provide normal replacement of luminaire glassware and lamps, and paint metal parts as needed; all other maintenance and replacement of the customer's equipment shall be paid for by the customer.

Company-Owned

In Company-owned systems consisting of one or more luminaries, the Company shall furnish, install and own all equipment comprising the unmetered lighting system. The Company shall supply the energy, and renew and maintain the entire equipment. In areas where the Company has installed an underground electric distribution system pursuant to the Company's residential underground electric distribution policy as set forth in its Electric Rate Book, the unmetered lighting system shall be served from said underground electric distribution system. In all other areas, the unmetered lighting system shall normally be served from overhead lines or from underground cables installed at customer's request pursuant to special unmetered lighting provisions contained in Monthly Rate clause and Facilities Policy.

Outdoor Lighting

For existing outdoor lighting, luminaires and control equipment shall be furnished, owned, installed and maintained by the Company. Luminaires shall be installed on Company-owned or Company-leased poles and must be accessible to the Company's construction and maintenance equipment.

Facilities Policy:

Customer-Owned

At the customer's request, the Company shall install, at its own cost, its distribution facilities under this rate to the extent that the cost of such installation does not exceed the allowance granted under the Company's general service line extension policy. Costs of facilities in excess of the free allowance shall require an advance, nonrefundable, contribution in the amount by which the estimated costs exceed the free allowance.

(Continued on Sheet No. D-89.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-88.00)

Facilities Policy: (Contd)

Company-Owned

At the customer's request, the Company shall install new luminaires and associated facilities under this rate, or replace existing luminaires and associated facilities served under this rate with other luminaires and associated facilities for which it has rates available in accordance with the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond 350 feet shall require a contribution based on the Company's general service line extension policy.

B. At the customer's request, the Company shall convert its existing incandescent/fluorescent luminaires to the nearest standard size high-pressure sodium luminaire at no cost to the customer. If requirements for installations make it necessary for the Company to convert luminaires or if the customer requests a conversion of luminaires that the Company can no longer maintain due to federal or state requirements, the Company shall cover the cost of the bulb and the customer shall be responsible for all other expenses as a contribution. For conversions completed with normal Company maintenance such as replacement of bulbs on a routine schedule or due to failure, then the average cost of that work type shall be deducted from the total work order cost to determine the required customer contribution. If other light upgrading is also involved, the Company expenditure shall be calculated in accordance with the Company's general service line extension policy. Any costs in excess of this amount shall be borne by the customer.

   Additional annual revenue is the greater of (1) the difference between the annual revenue from the nearest size high-pressure sodium luminaire and the annual delivery revenue from the upgraded light which would be installed or (2) the difference between the annual delivery revenue from the existing light and the annual delivery revenue from the light which would be installed.

C. Where upgrading of high-pressure sodium unmetered lights are requested, the customer shall pay the estimated cost of conversion. Where the upgrading results in additional revenues to the Company, the customer shall receive a credit calculated in accordance with the Company's general service line extension policy to be applied against the estimated cost of conversion. If the cost of conversion is overestimated, the Company shall, upon completion of construction, refund that portion of the contribution resulting from the overestimate.

D. Where Company-approved nonstandard poles are requested, the customer contribution shall be the difference in installed cost between standard wood poles and the requested pole. Where Company-approved nonstandard fixtures are requested, a customer contribution shall be required to cover costs in excess of the equivalent Company standard fixture.

E. For unmetered lighting systems installed underground (exclusive of subdivisions where the developer's contribution provided for underground unmetered lighting), the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction. No contribution shall be required for that footage of unmetered lighting cable which can be satisfactorily installed in underground conduit furnished by the customer for the Company's use and in accordance with the Company's specification.

F. For system-wide conversions from one light source to another, the customer may be limited to an annual quota as determined by the Company.

G. If underground unmetered lighting cable is requested, except that requested in conjunction with the Company's residential underground electric distribution policy, the customer shall contribute to the Company the difference between the Company's estimated installed costs of the underground unmetered lighting cable and the Company's estimated installed costs of standard overhead unmetered lighting conductors.

(Continued on Sheet No. D-90.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-89.00)

Monthly Rate

Transitional Rates, effective *March 18, 2022* through June 30, 2022:

The charge per luminaire per month shall be

	Nominal Rating of Lamps (One Lamp per Luminaire) (1)			Service Charge per Luminaire (4)			
Type of Luminaire	**Watts**	**Watts Including Ballast (2)**	**Lumens**	Non-Capacity	Capacity	Total	**Fixture Charge per Luminaire (4)**
Mercury Vapor (3)	100	128	3,500	$9.72	$0.00	$9.72	$3.00
Mercury Vapor (3)	175	209	7,500	13.28	0.00	13.28	3.00
Mercury Vapor (3)	250	281	10,000	16.45	0.00	16.45	3.00
Mercury Vapor (3)	400	458	20,000	*24.23*	0.00	*24.23*	3.00
Mercury Vapor (3)	700	770	35,000	37.96	0.00	37.96	3.00
Mercury Vapor (3)	1,000	1,080	50,000	*51.59*	0.00	*51.59*	3.00
High-Pressure Sodium (3)	70	83	5,000	7.74	0.00	7.74	3.00
High-Pressure Sodium	100	117	8,500	9.23	0.00	9.23	3.00
High-Pressure Sodium	150	171	14,000	11.61	0.00	11.61	3.00
High-Pressure Sodium (3)	200	247	20,000	*14.96*	0.00	*14.96*	3.00
High-Pressure Sodium	250	318	24,000	*18.07*	0.00	*18.07*	3.00
High-Pressure Sodium	400	480	45,000	*25.20*	0.00	*25.20*	3.00
Fluorescent (3)	380	470	20,000	*24.76*	0.00	*24.76*	3.00
Incandescent (3)	202	202	2,500	*12.98*	0.00	*12.98*	3.00
Incandescent (3)	305	305	4,000	17.51	0.00	17.51	3.00
Incandescent (3)	405	405	6,000	*21.90*	0.00	*21.90*	3.00
Incandescent (3)	690	690	10,000	*34.44*	0.00	*34.44*	3.00
Metal Halide (3)	150	170	9,750	*11.56*	0.00	*11.56*	3.00
Metal Halide (3)	175	210	10,500	13.33	0.00	13.33	3.00
Metal Halide (3)	250	290	15,500	*16.84*	0.00	*16.84*	3.00
Metal Halide (3)	400	460	24,000	24.33	0.00	24.33	3.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, the Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For Customer-Owned lighting fixtures that are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a *22.6%* Power Supply Charge and a *77.4%* Distribution Charge.

For Company-Owned lighting fixtures that are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a 15.6% Power Supply Charge and a 84.4% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-90.10)

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

Third Revised Sheet No. D-90.10
Cancels Second Revised Sheet No. D-90.10

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.00)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$10.39*	*$10.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$11.02*	*$11.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$11.64*	*$12.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$12.27*	*$13.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$12.90*	*$14.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$13.52*	*$14.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$14.15*	*$15.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$14.77*	*$16.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$15.40*	*$17.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$16.03*	*$18.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$16.65*	*$19.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.28*	*$20.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$17.90*	*$20.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$18.53*	*$21.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$19.16*	*$22.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$19.78*	*$23.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$20.41*	*$24.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$21.03*	*$25.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$21.66*	*$25.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$22.29*	*$26.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$22.91*	*$27.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$23.54*	*$28.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$24.17*	*$29.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$24.79*	*$30.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$25.42*	*$30.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$26.04*	*$31.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$26.67*	*$32.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$27.30*	*$33.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$27.92*	*$34.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$28.55*	*$35.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$29.17*	*$35.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$29.80*	*$36.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$30.43*	*$37.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$31.05*	*$38.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$31.68*	*$39.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$32.30*	*$40.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$32.93*	*$40.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$33.56*	*$41.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$34.18*	*$42.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$34.81*	*$43.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$35.44*	*$44.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$36.06*	*$45.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$36.69*	*$45.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$37.31*	*$46.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$37.94*	*$47.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$38.57*	*$48.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$39.19*	*$49.33*

(Continued on Sheet No. D-90.20)

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

Effective for service rendered on
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M.P.S.C. No. 14 – Electric
Consumers Energy Company
(To revise prices)

Fourth Revised Sheet No. D-90.20
Cancels Third Revised Sheet No. D-90.20

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

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

(Continued on Sheet No. D-91.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-90.20)

Monthly Rate: (Contd)

Green Generation Program:

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

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

Renewable Energy Credit (REC) Programs:

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

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

General Terms, Surcharges, Power Supply Cost Recovery (PSCR) Factor and Securitization Charges:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00, Surcharges shown on Nos. D-2.00 through D-5.00, PSCR Factor shown on Sheet No. D-6.00 and the Securitization Charges shown on Sheet *Nos.* D-7.00 *and D-7.10.*

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions:

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, annual charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

(Continued on Sheet No. D-92.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-91.00)

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the capacity requirements in watts of the lamp(s) including ballast(s) times the monthly Burning Hours as defined below divided by 1,000.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. For 24-hour service, unmetered lighting shall be burning 24 hours per day.

The Company shall replace or repair, at its own cost, unmetered lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL UNMETERED *LIGHT EMITTING DIODE* LIGHTING RATE GU-*LED*

Availability:

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways for unmetered streetlighting service where the Company has existing distribution lines available for supplying energy for unmetered light-emitting diode (LED) *lighting* or for any Company-owned *LED* streetlighting system consisting of one or more luminaires. This rate is not available for resale purposes or for Retail Open Access Service. Installations under this rate shall require a written agreement.

Nature of Service:

Company-Owned Option

In Company-owned systems, the Company shall select, furnish, install and own all equipment for any new unmetered *LED* lighting or for any modifications to existing Company-owned equipment. The Company shall supply the energy and maintain all equipment. In areas where the Company's facilities are underground or required to be placed underground or the customer requests underground facilities, the unmetered lighting system shall be served from underground cables pursuant to the provisions contained in this Rate Schedule. In all other areas, the unmetered lighting system shall normally be served from overhead lines pursuant to the provisions contained in this Rate Schedule.

Customer-Owned Option

The capacity requirements of the customer-owned Unmetered *LED* Lighting served under this rate shall be determined by the Company based on verifiable documentation supplied by the customer. The Company shall have the right to test such capacity requirements. In the event that said tests show capacity requirements different from those indicated by the documentation supplied by the customer, the Company's test capacity value shall be used for billing purposes.

In customer-owned systems, control equipment shall be furnished and owned by the Company. The customer shall furnish, install and maintain the equipment comprising the unmetered *LED* lighting system including, but not limited to, poles, the overhead wires or underground cables between the luminaires and the supply circuits extending to the point of attachment with the Company's lines. The customer's *LED* lighting fixtures and equipment must be approved in advance by the Company before purchase and installation for service under this rate. The Company shall connect the customer's equipment to the Company's lines in a manner consistent with the Company's engineering standards, supply the energy and control the burning hours of the experimental lighting. Maintenance and replacement of the customer-owned equipment shall be the responsibility of the customer.

Existing unmetered installations with customer-owned fixtures on Company-owned distribution equipment must be converted to the customer-owned system described above or the Company-owned system described below to receive service under this Rate Schedule. Such installations may also be converted to a customer-owned metered system and receive service under Rate Schedule GML. Conversion costs shall be the responsibility of the customer.

Facilities Policy:

Company-Owned Option

Following execution of a written agreement, the Company shall install *LED* lighting and associated facilities available under this rate under the following guidelines:

A. The installation of all new, standard unmetered lights shall require a customer contribution of $100 per luminaire. This policy includes the extension of up to 350 feet of distribution facilities to serve any individual light. Any extension beyond this amount shall require a contribution based on the Company's general service line extension policy. For unmetered lighting systems *fed by* underground *electric lines*, the customer shall be required to contribute the estimated difference in cost between the equivalent standard overhead construction and required underground construction.

B. The conversion of existing unmetered lights *to LED* shall require a customer contribution per luminaire equal to the incremental additional cost to be incurred by the Company. *A credit* of $200 *per light shall be applied to the incremental cost* for the conversion of existing luminaires that are closed to new business *when* converted to the *luminaire recommended* by the Company.

C. For light upgrades, such as the replacement of fixtures to a size greater or less than the next equivalent value, Company expenditures for additional facilities beyond those described above shall be calculated in accordance with the Company's general service line extension policy.

(Continued on Sheet No. D-94.00)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-93.00)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine LED lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of LED lighting available under this rate.

E. For customer requested material requiring special order, an additional per luminaire per month charge may apply for procurement and material handling. The Company and the Customer shall mutually agree to the monthly charge prior to procurement and installation of the special order material.

F. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered LED Lighting option.

G. Any charges, deposits or contributions may be required in advance of commencement of construction.

H. At the Company's discretion, any fixture may be converted to LED at no cost to the customer. The replaced fixture will be moved to General Unmetered Light Emitting Diode Lighting Rate GU-LED upon completion of the installation and reconciliation of the community's streetlighting inventory for billing accuracy.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Company-Owned Conversion Credit:

A conversion credit may be available to Customers who converted to LED municipal streetlighting.

Customers who converted to LED streetlighting before April 1, 2018 are eligible for the following Conversion Credit per billing month beginning with the January 2021 billing month through the December 2028 billing month:

Fixture Credit per Luminaire: $(*8.11*) per month

(Continued on Sheet No. D-94.10)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.00)

Monthly Rate (Contd)

Transitional Unmetered Lighting Rate GU-LED Charges, effective *March 18, 2022* through June 30, 2022:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$8.32*	*$8.66*
25-34 W	Per Light	*$0.51*	$0.00	*$0.51*	$8.98	*$9.49*
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$9.64	*$10.32*
45-54 W	Per Light	*$0.86*	$0.00	$0.86	*$10.31*	*$11.17*
55-64 W	Per Light	*$1.03*	$0.00	$1.03	*$10.97*	*$12.00*
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$11.63	*$12.83*
75-84 W	Per Light	*$1.37*	$0.00	*$1.37*	*$12.30*	$13.67
85-94 W	Per Light	*$1.54*	$0.00	*$1.54*	*$12.96*	$14.50
95-104 W	Per Light	*$1.71*	$0.00	*$1.71*	*$13.62*	$15.33
105-114 W	Per Light	*$1.88*	$0.00	*$1.88*	$14.28	*$16.16*
115-124 W	Per Light	*$2.05*	$0.00	*$2.05*	*$14.95*	*$17.00*
125-134 W	Per Light	*$2.23*	$0.00	*$2.23*	*$15.61*	$17.84
135-144 W	Per Light	*$2.40*	$0.00	*$2.40*	$16.27	*$18.67*
145-154 W	Per Light	*$2.57*	$0.00	*$2.57*	*$16.94*	$19.51
155-164 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.60*	*$20.34*
165-174 W	Per Light	*$2.91*	$0.00	*$2.91*	*$18.26*	*$21.17*
175-184 W	Per Light	*$3.08*	$0.00	*$3.08*	*$18.93*	*$22.01*
185-194 W	Per Light	*$3.25*	$0.00	*$3.25*	*$19.59*	*$22.84*
195-204 W	Per Light	*$3.42*	$0.00	*$3.42*	*$20.25*	*$23.67*
205-214 W	Per Light	*$3.59*	$0.00	*$3.59*	*$20.92*	*$24.51*

Customer-Owned Equipment		Energy Charges			Delivery	Monthly Cost Per Light
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	$0.34	$0.00	$0.34	*$5.32*	*$5.66*
25-34 W	Per Light	*$0.51*	$0.00	*$0.51*	$5.98	*$6.49*
35-44 W	Per Light	*$0.68*	$0.00	*$0.68*	$6.64	*$7.32*
45-54 W	Per Light	*$0.86*	$0.00	$0.86	*$7.31*	*$8.17*
55-64 W	Per Light	*$1.03*	$0.00	$1.03	*$7.97*	*$9.00*
65-74 W	Per Light	*$1.20*	$0.00	*$1.20*	$8.63	*$9.83*
75-84 W	Per Light	*$1.37*	$0.00	*$1.37*	*$9.30*	$10.67
85-94 W	Per Light	*$1.54*	$0.00	*$1.54*	*$9.96*	$11.50
95-104 W	Per Light	*$1.71*	$0.00	*$1.71*	*$10.62*	$12.33
105-114 W	Per Light	*$1.88*	$0.00	*$1.88*	$11.28	*$13.16*
115-124 W	Per Light	*$2.05*	$0.00	*$2.05*	*$11.95*	*$14.00*
125-134 W	Per Light	*$2.23*	$0.00	*$2.23*	*$12.61*	$14.84
135-144 W	Per Light	*$2.40*	$0.00	*$2.40*	$13.27	*$15.67*
145-154 W	Per Light	*$2.57*	$0.00	*$2.57*	*$13.94*	$16.51
155-164 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.60*	*$17.34*
165-174 W	Per Light	*$2.91*	$0.00	*$2.91*	*$15.26*	*$18.17*
175-184 W	Per Light	*$3.08*	$0.00	*$3.08*	*$15.93*	*$19.01*
185-194 W	Per Light	*$3.25*	$0.00	*$3.25*	*$16.59*	*$19.84*
195-204 W	Per Light	*$3.42*	$0.00	*$3.42*	*$17.25*	*$20.67*
205-214 W	Per Light	*$3.59*	$0.00	*$3.59*	*$17.92*	*$21.51*

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-5.00 and the Power Plant Securitization Charges shown on Sheet No. D-7.00.

(Continued on Sheet No. D-94.20)

Issued March 23, 2022 by
Garrick J. Rochow,
President and Chief Executive Officer,
Jackson, Michigan

Effective for service rendered on
and after March 18, 2022

Issued under authority of the
Michigan Public Service Commission
dated March 17, 2022
in Case No. U-20963

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.10)

Monthly Rate (Contd)

Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Company-Owned Equipment		Energy Charges			Delivery	Monthly Cost
		Non-Capacity	Capacity	Total		
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$10.39*	*$10.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$11.02*	*$11.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$11.64*	*$12.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$12.27*	*$13.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$12.90*	*$14.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$13.52*	*$14.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$14.15*	*$15.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$14.77*	*$16.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$15.40*	*$17.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$16.03*	*$18.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$16.65*	*$19.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$17.28*	*$20.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$17.90*	*$20.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$18.53*	*$21.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$19.16*	*$22.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$19.78*	*$23.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$20.41*	*$24.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$21.03*	*$25.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$21.66*	*$25.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$22.29*	*$26.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$22.91*	*$27.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$23.54*	*$28.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$24.17*	*$29.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$24.79*	*$30.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$25.42*	*$30.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$26.04*	*$31.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$26.67*	*$32.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$27.30*	*$33.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$27.92*	*$34.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$28.55*	*$35.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$29.17*	*$35.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$29.80*	*$36.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$30.43*	*$37.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$31.05*	*$38.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$31.68*	*$39.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$32.30*	*$40.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$32.93*	*$40.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$33.56*	*$41.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$34.18*	*$42.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$34.81*	*$43.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$35.44*	*$44.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$36.06*	*$45.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$36.69*	*$45.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$37.31*	*$46.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$37.94*	*$47.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$38.57*	*$48.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$39.19*	*$49.33*

(Continued on Sheet No. D-94.30)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.20)

Monthly Rate (Contd)
Universal Unmetered Streetlighting Rates, effective for service rendered on and after *March 15, 2024*:

Customer-Owned Equipment		Energy Charges Non-Capacity	Capacity	Total	Delivery	Monthly Cost Per Light
15-24 W	Per Light	*$0.41*	$0.00	*$0.41*	*$7.39*	*$7.80*
25-34 W	Per Light	*$0.62*	$0.00	*$0.62*	*$8.02*	*$8.64*
35-44 W	Per Light	*$0.84*	$0.00	*$0.84*	*$8.64*	*$9.48*
45-54 W	Per Light	*$1.05*	$0.00	*$1.05*	*$9.27*	*$10.32*
55-64 W	Per Light	*$1.26*	$0.00	*$1.26*	*$9.90*	*$11.16*
65-74 W	Per Light	*$1.47*	$0.00	*$1.47*	*$10.52*	*$11.99*
75-84 W	Per Light	*$1.68*	$0.00	*$1.68*	*$11.15*	*$12.83*
85-94 W	Per Light	*$1.89*	$0.00	*$1.89*	*$11.77*	*$13.66*
95-104 W	Per Light	*$2.10*	$0.00	*$2.10*	*$12.40*	*$14.50*
105-114 W	Per Light	*$2.32*	$0.00	*$2.32*	*$13.03*	*$15.35*
115-124 W	Per Light	*$2.53*	$0.00	*$2.53*	*$13.65*	*$16.18*
125-134 W	Per Light	*$2.74*	$0.00	*$2.74*	*$14.28*	*$17.02*
135-144 W	Per Light	*$2.95*	$0.00	*$2.95*	*$14.90*	*$17.85*
145-154 W	Per Light	*$3.16*	$0.00	*$3.16*	*$15.53*	*$18.69*
155-164 W	Per Light	*$3.37*	$0.00	*$3.37*	*$16.16*	*$19.53*
165-174 W	Per Light	*$3.59*	$0.00	*$3.59*	*$16.78*	*$20.37*
175-184 W	Per Light	*$3.80*	$0.00	*$3.80*	*$17.41*	*$21.21*
185-194 W	Per Light	*$4.01*	$0.00	*$4.01*	*$18.03*	*$22.04*
195-204 W	Per Light	*$4.22*	$0.00	*$4.22*	*$18.66*	*$22.88*
205-214 W	Per Light	*$4.43*	$0.00	*$4.43*	*$19.29*	*$23.72*
215-224 W	Per Light	*$4.64*	$0.00	*$4.64*	*$19.91*	*$24.55*
225-234 W	Per Light	*$4.85*	$0.00	*$4.85*	*$20.54*	*$25.39*
235-244 W	Per Light	*$5.07*	$0.00	*$5.07*	*$21.17*	*$26.24*
245-254 W	Per Light	*$5.28*	$0.00	*$5.28*	*$21.79*	*$27.07*
255-264 W	Per Light	*$5.49*	$0.00	*$5.49*	*$22.42*	*$27.91*
265-274 W	Per Light	*$5.70*	$0.00	*$5.70*	*$23.04*	*$28.74*
275-284 W	Per Light	*$5.91*	$0.00	*$5.91*	*$23.67*	*$29.58*
285-294 W	Per Light	*$6.12*	$0.00	*$6.12*	*$24.30*	*$30.42*
295-304 W	Per Light	*$6.34*	$0.00	*$6.34*	*$24.92*	*$31.26*
305-314 W	Per Light	*$6.55*	$0.00	*$6.55*	*$25.55*	*$32.10*
315-324 W	Per Light	*$6.76*	$0.00	*$6.76*	*$26.17*	*$32.93*
325-334 W	Per Light	*$6.97*	$0.00	*$6.97*	*$26.80*	*$33.77*
335-344 W	Per Light	*$7.18*	$0.00	*$7.18*	*$27.43*	*$34.61*
345-354 W	Per Light	*$7.39*	$0.00	*$7.39*	*$28.05*	*$35.44*
355-364 W	Per Light	*$7.60*	$0.00	*$7.60*	*$28.68*	*$36.28*
365-374 W	Per Light	*$7.82*	$0.00	*$7.82*	*$29.30*	*$37.12*
375-384 W	Per Light	*$8.03*	$0.00	*$8.03*	*$29.93*	*$37.96*
385-394 W	Per Light	*$8.24*	$0.00	*$8.24*	*$30.56*	*$38.80*
395-404 W	Per Light	*$8.45*	$0.00	*$8.45*	*$31.18*	*$39.63*
405-414 W	Per Light	*$8.66*	$0.00	*$8.66*	*$31.81*	*$40.47*
415-424 W	Per Light	*$8.87*	$0.00	*$8.87*	*$32.44*	*$41.31*
425-434 W	Per Light	*$9.09*	$0.00	*$9.09*	*$33.06*	*$42.15*
435-444 W	Per Light	*$9.30*	$0.00	*$9.30*	*$33.69*	*$42.99*
445-454 W	Per Light	*$9.51*	$0.00	*$9.51*	*$34.31*	*$43.82*
455-464 W	Per Light	*$9.72*	$0.00	*$9.72*	*$34.94*	*$44.66*
465-474 W	Per Light	*$9.93*	$0.00	*$9.93*	*$35.57*	*$45.50*
475-484 W	Per Light	*$10.14*	$0.00	*$10.14*	*$36.19*	*$46.33*

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

(Continued on Sheet No. D-95.00)

GENERAL UNMETERED LIGHT EMITTING DIODE LIGHTING RATE GU-LED

(Continued From Sheet No. D-94.30)

General Terms

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

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec	Total
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered LED Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

Maintenance of Lighting:

The Company shall replace or repair, at its own cost, Company-Owned Unmetered LED Lighting equipment that is out of service. *A streetlighting outage credit shall be applied to the customer's bill for out of service lighting. The credit shall include the Monthly Cost Per Light and applicable surcharges prorated for the specific timeframe of the outage, beginning on the date the outage was reported and documented and terminating on the date service is restored. The streetlighting outage credit shall be applied to the customer's bill within 90 days of restoration. Outages may be reported using the Company's Streetlighting Outage and Reporting Map (https://streetlights.consumersenergy.com).*

Outages caused by factors beyond the Company's reasonable control as provided for in Rules C1.1, Character of Service, and C3., Emergency Electrical Procedures, of the Company's Electric Rate Schedule are not covered by this policy. Such outages would be handled consistent with the particular circumstances and no credit would be made for such outages.

Renewable Energy Credit (REC) Programs:

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

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

Term and Form of Contract:

All service under this rate shall require a written contract with an initial term of five years or more.

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	Capacity	Total	
$*0.074181*	$*0.002717*	$*0.076898*	per kWh for all kWh

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

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$*0.026586*	per kWh for all kWh

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

(Continued on Sheet No. D-97.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-96.00)

Monthly Rate: (Contd)

Determination of kWh:

The monthly charge shall be the per kWh total of the Power Supply and Delivery Charges as shown above based on the capacity requirements in Kilowatts of the lamp(s), associated ballast(s) and control equipment assuming 4,200 burning hours per year, adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption. At the Company's option, such service may be metered and the metered kWh used as the basis for billing. The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

For dusk to midnight service for energy-only unmetered lighting, the monthly charge per kWh shall be 130% of the sum of the Secondary Energy Charge and Distribution Charge per kWh for secondary service. The annual kWh shall be based on the actual burning hours. The monthly kWh for billing shall be the annual kWh adjusted by the ratio of the monthly kWh consumption to the total annual kWh consumption.

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be 50% of the total kWh so calculated. The kWh for continuous, nonintermittent devices shall be 100% of the total kWh so calculated. No reduction in kWh shall be made for devices not operated 24 hours per day, or not operated every day.

The kWh of devices used for the control of school traffic, and operated not more than six hours per day during the school year only, shall be 10% of the continuous or cyclical kWh calculated.

The kWh for CATV Power Supply Units shall be 50% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The kWh for Wireless Access and Security Camera Power Supply Units shall be 100% of the total kWh as determined from the manufacturer's rated input capacity of the Power Supply Units or the actual test load, whichever is greater.

The Company may, at its option, install test meters for the purpose of determining the monthly kWh usage to be used for billing purposes.

(Continued on Sheet No. D-98.00)

GENERAL SERVICE UNMETERED RATE GU

(Continued From Sheet No. D-97.00)

Monthly Rate (Contd)

Green Generation Program

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

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

Renewable Energy Credit (REC) Programs:

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

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

General Terms

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

Minimum Charge

The System Access Charge included in the rate, plus any applicable non-consumption based surcharges.

Due Date and Late Payment Charge

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Special Terms and Conditions

The Company reserves the right to make special contractual arrangements as to term or duration of contract, termination charges, contribution in aid of construction, monthly charges or other special considerations when the customer requests service, equipment or facilities not normally provided under this rate.

Term and Form of Contract

Traffic Lighting, Wireless Access and Security Camera service under this rate may require a written contract for a term of reasonable duration.

All service under this rate to Community Antenna Television Service Companies shall require a written contract with a minimum term of one year.

Designees for Copies of Contracts

The Company designates a primary and secondary contact to assist with requested customer contract review. The designated contacts are:

Primary Designee:

Name: Sarah Jorgensen
Email: sarah.jorgensen@cmsenergy.com
Office Phone: (517) 788-2349

Secondary Designee:

Name: Natalie Busack
Email: NATALIE.BUSACK@cmsenergy.com
Office Phone: (517) 788-0931

Attachment JJ

Jester Affidavit Signed September 8, 2025

UNITED STATES OF AMERICA

BEFORE THE

UNITED STATES DEPARTMENT OF ENERGY

Order No. 202-25-7

AFFIDAVIT OF DOUGLAS JESTER

Douglas Jester states that the following information is true and accurate to the best of my knowledge and belief:

1. I am the Managing Partner of 5 Lakes Energy, a clean-energy consulting firm. Previously, I served in various roles in Michigan state government and in the private sector. I began my career in ecosystem modeling, working for the State of Michigan from 1977 to 1999. In 2011, I cofounded 5 Lakes Energy.
2. I have a masters degree in statistics from Virginia Polytechnic Institute & State University and completed coursework for a Ph.D. in Environmental Economics from Michigan State University. I am a frequent expert witness before the Michigan Public Service Commission (MPSC).
3. I have used the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA) regularly in my work, in part because the MPSC requires utilities in Michigan to use the COBRA tool to develop integrated resource plans.
4. The COBRA tool is a web-based model developed and maintained by the U.S. Environmental Protection Agency (EPA) to model the co-benefits of reductions in greenhouse gasses.[1] Those co-benefits are the benefits to public health due to reductions in co-pollutants, namely $PM_{2.5}$, NOx, SO_2, and VOCs.
5. The COBRA tool allows for the modeling of health impacts over time, based on emissions over a particular year. The model allows a user to specify

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[1] *See* U.S. EPA, User's Manual for the Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA), Version: 5.2 (March 2025), *https://www.epa.gov/system/files/documents/2025-03/cobra-user-manual-v5.2.pdf*

particular scenarios of emission controls. It is available at: https://cobra.epa.gov/.

6. To estimate the health impacts of running the J.H. Campbell Plant during the pendency of the Extension Order, I used the COBRA tool as follows.
7. I first selected the relevant county in Michigan—Ottawa County.
8. I then identified the relevant sector—Fuel Combustion: Electric Utility—and subsector—Coal.
9. I am aware that the J.H. Campbell plant is the only coal-fired power plant in Ottawa County.
10. I then selected a 100% reduction in each of the relevant pollutants.
11. Together, these parameters reflect the closure of the J.H. Campbell plant.
12. Finally, I selected a discount rate—2%.
13. The resulting figures provide an estimate for the health benefits over time of a year's worth of emissions reductions from the closure of the J.H. Campbell plant.
14. These figures also provide an estimate of the health harms resulting from the continued operation of the J.H. Campbell plant.
15. According to the COBRA tool, those harms in all contiguous U.S. states include 27-36 excess deaths, as well as thousands of lost school and work days. In total, the COBRA tool estimates that the total monetized value of health effects are $420 million to $700 million in 2023 dollars.
16. I also filtered the results of the model to show health effects in Michigan only. For Michigan alone, the COBRA model estimates 8.1 - 13 excess deaths and monetized health effects of $130 million to $200 million.
17. These estimates of public-health benefits produced by the COBRA tool are based on closing the J.H. Campbell plant for a year.
18. I understand that the Extension Order prevents the J.H. Campbell plant from closing from August 21, 2025, to November 19, 2025.
19. As a rough approximation, the benefits from closing the plant for the three-month period of the Extension Order would be one quarter the benefits of a year-long closure.
20. To precisely estimate the harm from the continued operation of the J.H. Campbell plant, one would need to know, or model, which generation resources are displaced by its operation. Such precision is unrealistic. But it is almost certainly true that most of the generation displaced by the continued operation of J.H. Campbell comes from natural gas combined cycle plants.

21. The health impacts from running those plants vary depending on location, time of year, and the specific technologies employed by the plant, but they are invariably less than coal.
22. Accordingly, I can conclude that the continued operation of the J.H. Campbell plant will have a net harmful effect on public health in Michigan.

Douglas B Jester

Douglas Jester

Attachment K

MPSC Case No. U-21775, MPSC Order, August 21, 2025

S T A T E   O F   M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2028/2029 planning year as required by MCL 460.6w.	)	Case No. U-21775
In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations for the 2029/2030 planning year as required by MCL 460.6w.	)	Case No. U-21907

At the August 21, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick, Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

Background and Procedural History

Public Act 3 of 1939, as amended by Public Act 341 of 2016 (Act 341), MCL 460.6w(8) (Section 6w(8)), requires each electric utility, alternative electric supplier (AES), cooperative electric utility, and municipally owned electric utility to demonstrate to the Commission, in a format determined by the Commission, that each load serving entity (LSE) owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator (ISO), or the Commission, as applicable.[1] This is known as a state reliability mechanism (SRM) capacity demonstration.

Act 341 states that regulated electric utilities' capacity demonstration filings are due by December 1 each year, with filings by AESs, cooperatives, and municipally owned electric utilities due by the seventh business day in February each year. MCL 460.6w(8)(a)-(b). However, the statute also allows the Commission to adjust these dates to ensure proper alignment with the ISO's procedures and requirements. MCL 460.6w(10). In the September 15, 2017 order in Case No. U-18197 (September 15 order), the Commission adopted a format for the capacity demonstration filings required by Section 6w(8), including templates for reporting and for affidavits.[2] Each year, the Commission opens a docket for the purpose of receiving those filings, and sets due dates for the filings and for the Commission Staff's (Staff's) report providing an analysis of the sufficiency of each LSE's capacity demonstration.

In the August 22, 2024 order in Case Nos. U-21393 *et al*. (August 22 order), the Commission opened the docket in Case No. U-21775 for the purpose of receiving the LSEs'

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[1] MCL 460.6w(12)(a) defines the appropriate ISO as the Midcontinent Independent System Operator, Inc. (MISO). MCL 460.6w(11) also states that "[n]othing in this act shall prevent the commission from determining a generation capacity charge under the reliability assurance agreement, rate schedule FERC [Federal Energy Regulatory Commission] No. 44 of the independent system operator known as PJM Interconnection, LLC [PJM]. . . ."

[2] The filing requirements have been slightly modified in the intervening years. *See*, September 13, 2018 order in Case No. U-20154. In the March 17, 2019 order in Case No. U-20154, the Commission also approved a protective order for use with capacity demonstration filings. That protective order may also be used in Case No. U-21907 for the 2029/2030 capacity demonstration.

capacity demonstrations for the 2028/2029 planning year (PY).[3] In response to a shift to a seasonal capacity auction and other developments at MISO, the Commission adjusted the capacity demonstration filing dates as permitted under Section 6w(10) and directed larger investor-owned utilities (IOUs)[4] to file by February 24, 2025; smaller IOUs to file by March 3, 2025; and AESs, cooperatives, and municipally owned utilities to file by March 17, 2025. The Commission also directed the Staff to file its analysis of the demonstrations no later than May 12, 2025.

On February 27, 2025, the Commission issued an order in Case Nos. U-21393 *et al.* (February 27 order) granting a motion for clarification filed by Energy Michigan regarding the requirements applicable to the capacity demonstrations filed by AESs pursuant to Section 6w(8)(b). In the February 27 order, the Commission clarified the wording in the Capacity Demonstration Process and Requirements document and General Affidavit to align with its previously expressed interpretation that Section 6w's four-year forward capacity demonstration requirement does not prevent an LSE from entering into other capacity agreements or contracts outside of the original capacity contract after the LSE has made its capacity obligation. Specifically, the Commission revised the language in the Capacity Demonstration Process and Requirements document and General Affidavit to read, "commitment

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[3] MCL 460.6w(8)(a) states that if an SRM is to be established, the Commission shall require, among other things, each electric utility to demonstrate by December 1 of each year that "for the planning year beginning 4 years after the beginning of the current planning year" that the utility owns or has contractual rights to sufficient capacity to meet its load obligations. Thus, the statute requires the capacity demonstrations to be four years out after the year the capacity demonstrations are required to be filed. As such, the capacity filings in Case No. U-21775 cover the 2028/2029 PY.

[4] A large IOU is considered to be an electric utility with one million customers or more, and a smaller IOU is considered to be an electric utility with less than one million customers.

to maintain the **contract** four years forward regardless of any early out provisions" rather than "commitment to maintain the **contracted amount** four years forward regardless of any early out provisions." February 27 order, p. 8 (emphasis in original to show revision); *see also*, *id*., Exhibits A, B, C, and D. The Commission also added language to the Capacity Demonstration Process and Requirements document, stating that "maintaining the contract four years forward" does not prohibit an LSE from selling surplus capacity to a buyer at some point in the future via a new contract. Additionally, the Commission included the following language in the revised Capacity Demonstration Process and Requirements document and General Affidavit to clarify that any surplus capacity sold must not be used by another LSE in that same year's demonstration to avoid the double counting of capacity: "Statements to achieve/maintain resources do not prohibit an LSE from entering into future transactions to sell surplus capacity provided that the same capacity is not used by another Michigan LSE as part of its capacity demonstration for the same planning year." February 27 order, pp. 8-9; *see also*, *id*., Exhibits A and B.

In compliance with Section 6w(8) and the August 22 order, all LSEs required to file capacity demonstrations by the directed deadlines have filed, and on May 12, 2025, the Staff filed its Capacity Demonstration Results: The Planning Year 2028/29 report (Staff Report).

Additionally, on April 29, 2025, the Staff filed the 2025 Statewide Energy Storage Target Calculation, which is the calculation that identifies each LSE serving customers in Michigan and its proportional share of the minimum statewide energy storage target, using peak load information for the previous five years filed in capacity demonstration filings under Section 6w. The Staff performed this calculation in accordance with the methodology approved by the Commission in the January 23, 2025 order in Case No. U-21571 (January 23 order). In the 2025

Statewide Energy Storage Target Calculation filing, the Staff explains that the calculation is to be used by LSEs filing either an energy storage plan or contracts for the necessary qualifying storage facilities in the current year, in accordance with Section 101 of Public Act 235 of 2023, MCL 460.1101. These calculations will be updated annually by the Staff to allow for LSEs filing in that year to use the most recent data. Future updates to the calculated storage capacity for each LSE will be filed by the Staff annually through 2029, in the open docket for LSE capacity demonstration filings, within 30 days after the completion of capacity demonstration filings as required under Section 6w for that year. *See*, Case No. U-21775, filing # U-21775-0057; *see also*, January 23 order, p. 29.

This order summarizes the Staff Report, addresses recommendations therein, and opens a new docket, Case No. U-21907, for the receipt of capacity demonstration filings for the 2029/2030 PY.

<u>The Commission Staff Report</u>

Following an executive summary of the Staff Report, the Staff explains that, as part of its pre-capacity demonstration process, it consulted with several LSEs to discuss the requirements of the capacity demonstration process.

Turning to the capacity demonstration filings, the Staff states that by February 24, 2025, DTE Electric Company (DTE Electric) and Consumers Energy Company (Consumers) filed capacity demonstrations; by March 3, 2025, Alpena Power Company, Indiana Michigan Power Company (I&M), Northern States Power Company, Upper Michigan Energy Resources Corporation, and Upper Peninsula Power Company filed capacity demonstrations; and by March 17, 2025, American Rural Cooperative, Bayfield Electric, Calpine Energy Solutions, LLC, City of Escanaba, City of Stephenson, City of Wakefield, Cloverland Electric Cooperative, CMS ERM Michigan LLC, Constellation NewEnergy Inc., Croswell Light and Power, Daggett Electric Department, NRG Energy Services LLC f/k/a Direct Energy Services LLC, Energy Harbor LLC, the Michigan Public Power Agency, Michigan South Central Power Agency (MSCPA), Newberry Water and Light Board, Union City Electric Department, Wolverine Power Supply Cooperative, Inc., and WPPI Energy filed capacity demonstrations. The Staff states that all LSEs, with the exception of MSCPA, discussed *infra*, were able to procure capacity necessary to demonstrate compliance in all four seasons of the 2028/2029 PY at the time of the LSE's filing. Per the Staff Report, two LSEs' filings indicated a shortage of capacity in the compliance year compared with projections of forecasted growth. However, Section 6w requires all LSEs to demonstrate enough resources to cover prompt-year obligations, and both LSEs met this requirement. Following a review of the two filings, the Staff determined that these entities demonstrated sufficient capacity. The Staff notes that both LSEs are in negotiations to acquire the appropriate amount of capacity needed to meet their forecasted growth. Staff Report, p. 6. The Staff adds that several AESs filed letters in the docket indicating that they are currently not serving customers in Michigan and, therefore, did not make a capacity demonstration filing.[5]

The Staff explains that it audited each capacity demonstration filing and requested more information when necessary. Per the Staff Report, each filing included the demonstration for the required compliance year (2028/2029 PY) and that most filings included an update for the 2025/2026 PY through the compliance year and complied with the Commission's directive in the

[5] The AESs that filed letters in Case No. U-21775 indicating that they are currently not serving customers in Michigan include the following: AEP Energy Inc.; BP Energy Retail Company LLC; Dillon Power LLC; Direct Energy Services LLC; Energy Services Providers, Inc.; Interstate Gas Supply, LLC; Just Energy Advanced Solutions LLC; ENGIE Power and Gas LLC; Energy International Power Marketing Corporation; MidAmerican Energy Services, LLC; Nordic Energy Services, LLC; Texas Retail Energy, LLC; and UP Power Marketing LLC. Staff Report, p. 6, n. 8.

August 22 order for LSEs to include data for the prompt year (2025/2026 PY) and interim years (2026/2027 PY and 2027/2028 PY) in their capacity demonstrations. In the cases of municipal and cooperative utilities that provided only the compliance year, the Staff states that it was able to estimate the amount of capacity available for the prompt and interim years. The Staff recommends that the Commission continue to require LSEs to include updated prompt and interim year capacity obligation and resource obligation information in future filings as this information aids the Staff in tracking changes to load and resources and in projecting the zonal resources adequacy more accurately. Staff Report, pp. 6-7.

Turning to MSCPA, the Staff indicates that at the time of the filing of the Staff Report, MSCPA did not have rights to sufficient capacity to meet its capacity obligations. The Staff explains that MSCPA was in the process of negotiating a bilateral contract to meet the deficiency with the intent to submit a revised capacity demonstration by the self-imposed deadline of September 1, 2025, showing sufficient resources to meet its capacity requirements. The Staff states that it met with MSCPA on April 30, 2025, to discuss its capacity compliance and to encourage urgency in securing the capacity necessary to meet its obligations. Staff Report, p. 7. Subsequent to the filing of the Staff report on May 12, 2025, MSCPA filed under seal a revised capacity demonstration on July 23, 2025. *See*, Case No. U-21775, filing # U-21775-0059. On August 12, 2025, the Staff filed a memorandum in Case No. U-21775 indicating that it had reviewed MSCPA's confidential filing and confirming that MSCPA acquired a new capacity resource to meet its 2028/2029 PY capacity requirements for all four seasons. *See*, Case No. U-21775, filing # U-21775-0060.

The Staff Report also gives an overview of zonal resource adequacy for Michigan, which contains load that spans two regional transmission organizations (RTOs), MISO and PJM, with the majority of the state's load located in MISO's footprint. Beginning with MISO resource adequacy, the Staff explains that Michigan LSEs serve load in MISO local resource zones (LRZs or zones) 1, 2, and 7.[6] The Staff then explains MISO's resource adequacy construct as follows:

> MISO establishes capacity obligations for all LSEs based on peak load forecasts and a planning reserve margin [(PRM)] percentage [ ] necessary to meet the North American Electric Reliability Corporation's (NERC['s]) Loss of Load Expectation (LOLE) standard of 1 day in 10 years. LSEs within MISO can meet their capacity requirements either through a Fixed Resource Adequacy Plan (FRAP), self-schedule, Reliability Based Demand Curve (RBDC) opt-out (new this planning year [. . . .]), paying the capacity deficiency charge, or through the Planning Resource Auction (PRA). The PRA is a residual market for LSEs that choose not to utilize other participation options or do not have enough capacity resources, either owned or purchased bilaterally, to satisfy their capacity obligations, and thus need to purchase additional resources.
>
> Within MISOs [sic] resource adequacy construct, the Planning Reserve Margin Requirement [PRMR] and the LCR [local clearing requirement] must be satisfied to meet the LOLE. The PRMR is determined through LOLE modeling based on the coincident MISO peak forecast and resources adjusted as necessary to meet the standard. PRMR resources are not location specific, i.e. they can come from outside an LSE's zone. Individual LSEs are responsible for their own share of the zone's PRMR. The ability to use imports to meet PRMR makes it likely all zones will meet this requirement. Failure to meet PRMR would only occur if there were not enough resources available within all of MISO's footprint or in the subregion (MISO North/Central or MISO South) given subregional transmission constraints.

Staff Report, p. 9.

Explaining the LCR further, the Staff states that the LCR is the minimum required capacity to be located within a zone to meet the LOLE standard while accounting for the zone's ability to import. The LCR is for the entire zone, not an individual LSE. The Staff notes that, at this time,

[6] The majority of the Lower Peninsula falls into Zone 7, with the exception of the southwest corner that is located within PJM's territory. The majority of the Upper Peninsula falls within Zone 2, with the exception of a small area in the most western corner that falls into Zone 1.

there is no LCR requirement under MCL 460.6w applicable to individual LSEs in Michigan.[7]

The Staff explains that:

> [t]he LCR is determined by performing a LOLE analysis on each zone individually, to determine the Local Reliability Requirement (LRR), or the

[7] MCL 460.6w(8) requires an LCR as part of the SRM capacity demonstrations. In the September 15 order, the Commission indicated that it would open a contested case to establish the LCR for future capacity demonstrations beginning in 2022 and beyond. September 15 order, pp. 40-42. This order was appealed on two grounds: (1) that the Commission lacked the authority to impose an LCR on individual providers and (2) that if the Commission has the authority, it must implement the LCR pursuant to a rulemaking under the Administrative Procedures Act of 1969 (APA), MCL 24.201 *et seq*. While the September 15 order was on appeal, the Commission issued an order in Case No. U-18444 establishing a methodology to apply the LCR to individual energy providers. June 28, 2018 order in Case No. U-18444, pp. 122-131. On September 13, 2018, the Commission issued an order (September 13 order) granting a motion for stay in Case No. U-18444, putting a hold on the implementation of the LCR pending the outcome of the appeal of the September 15 order. September 13 order, pp. 9-13. The Michigan Court of Appeals subsequently ruled that the Commission did not have the authority under Act 341 to impose an LCR on individual providers. *In re Reliability Plans of Electric Utilities for 2017-2021*, 325 Mich App 207, 221; 926 NW2d 584 (2018). The Court of Appeals did not address the second point of the appeal, which was that if the Commission did have such authority, the LCR requirement should be implemented through a rulemaking pursuant to the APA. The Michigan Supreme Court reversed the Court of Appeals, finding that the Commission does have the authority pursuant to MCL 460.6w to impose an LCR on individual providers and remanded the case to the Court of Appeals for further review to determine the Commission's compliance with the APA in imposing the LCR. *In re Reliability Plans of Electric Utilities for 2017-2021*, 505 Mich 97, 102; 949 NW2d 73 (2020). On December 3, 2020, the Court of Appeals held that the September 15 order (imposing an LCR on AESs individually in Case No. U-18197) did not equate to administrative rules in violation of the APA and did not exceed the Commission's authority granted by the Legislature. *In re Reliability Plans of Electric Utilities for 2017-2021*, unpublished per curiam opinion of the Court of Appeals, issued December 3, 2020 (Docket Nos. 340600 and 340607).

Energy Michigan, Inc. (Energy Michigan) and the Association of Businesses Advocating Tariff Equity (ABATE) filed a complaint in federal district court challenging the constitutionality of the individual LCR. On February 24, 2023, the United States District Court for the Eastern District of Michigan issued a judgment in favor of the Commission dismissing with prejudice the complaint filed by Energy Michigan and ABATE and finding that the plaintiffs did not meet their burden to show that the individual LCR requirement discriminates against interstate commerce, while the defendants established the necessity and legitimate purpose of the LCR in ensuring grid reliability that cannot be accomplished via reasonable nondiscriminatory alternatives. On March 24, 2023, the plaintiffs filed a joint notice of appeal of the February 24, 2023 final judgment to the United States Court of Appeals for the Sixth Circuit. Given the appeal, litigation regarding the LCR requirements is currently pending at the federal level.

> resources a zone would need to meet the loss-of-load standard if it were separated from MISO. Separately, MISO determines the import and export limits for each zone by performing a seasonal transfer analysis study. The study produces Zonal Import Ability (ZIA) and Zonal Export Ability (ZEA) values, which are then adjusted by the amount of controllable exports to non-MISO load to determine Capacity Import Limits (CIL) and Capacity Export Limits (CEL). The ZIA is an input to the LCR calculation, and the LCR, CEL, and CIL, and subregional constraints are inputs to the PRA clearing process.

Staff Report, p. 9.

The Staff states that in the 2023/2024 PY, MISO implemented a seasonal resource adequacy requirement for each summer, fall, winter, and spring season and a seasonal accredited capacity (SAC) methodology for certain resources participating in MISO's PRA to align with real time availability and planned outages. The Staff explains that it reviewed these changes with participants in technical conferences per the June 22, 2022 order in Case No. U-21099. The August 22 order (the capacity demonstration docket for the 2027/2028 PY) directed LSEs in MISO to demonstrate seasonal capacity obligations based on MISO's seasonal resource adequacy construct. Staff Report, p. 10. Discussing other changes in MISO, the Staff states that on June 27, 2024, FERC accepted MISO's RBDC tariff revisions to incorporate sloped demand curves into the PRA. *Id.*; *see also*, *Order Accepting Tariff Revisions*, 187 FERC ¶ 61,202 (June 27, 2024).

If an LRZ does not have enough resources to meet its seasonal requirements, the entire zone clears at the seasonal cost of new entry (seasonal CONE). For the 2025/2026 PY, seasonal CONE (in dollars per megawatt- (MW-) day) is equal to $130,930 per MW-year divided by the number of days in the seasons experiencing shortage in Zone 7. The Staff clarifies that this resource adequacy construct is based on probabilistic determinations and that failure to meet the requirements would not necessarily mean that the LRZ will experience a loss of load event. Staff Report, p. 10.

Providing further detail regarding the RBDC, the Staff explains that MISO introduced sloped demand curves in its resource adequacy construct in the 2025 PRA. Per the Staff Report, the systemwide RBDC addresses overall reliability needs across the entire system, while the subregional RBDCs capture additional reliability requirements specific to each subregion. While delayed for the time being due to the complexity of adding another 10 curves per season, MISO ultimately seeks to develop RBDCs at the LRZ level. The Staff then explains how MISO develops each curve and its relation to reliability and pricing metrics. Staff Report, pp. 10-11 (referencing MISO's Reliability-Based Demand Curves Conceptual Design White Paper (September 2023), available at 20230906 RASC Item 02 Draft RBDC White Paper630104.pdf (last accessed August 21, 2025)).

The Staff further explains that:

> [t]he RBDCs fundamentally change the objective function of the PRA, from minimizing as-offered costs to minimizing the difference between supply offers and demand offers to maximize social surplus. The clearing quantities may vary from the initial PRMR, but the value of the reliability contribution of any additional MWs cleared must be greater than or equal to the cost of procuring those MWs. The PRA is conducted using an optimization to simultaneously complete the following tasks: (1) meet the supply demand balance both for MISO and for each of the two Planning Areas (MISO North/Central and MISO South); (2) meet the LCR for each LRZ; (3) efficiently use transmission transfer capability between LRZs; and (4) respect the Sub-Regional Power Balance Constraint. Step 1 of the auction clearing process solves an optimization problem to identify which type of RBDC produces a higher MW obligation for a given subregion, share-of-Systemwide or Subregional. Step 2 of the process solves the clearing and pricing problem based on the RBDC identified in step 1 and outputs both the resource clearing (Final PRMR) and the auction clearing price (ACP) for each LRZ and External Resource Zone. A final step verifies the solution found in step 2. The auction clearing price is determined by where the supply offer curve meets the applicable RBDC, and is equal to the marginal cost of capacity, the regional marginal cost of capacity, the marginal cost of financially binding LCR, CEL, and CIL for an LRZ, and the marginal cost of financially binding Subregional Export Constraints and Subregional Import Constraints. For more information on auction clearing under RBDC[,] see Appendix M of MISO's Business Practice Manual 11.

Staff Report, p. 11. The Staff adds that MISO included an RBDC Opt-Out mechanism that allows an LSE to opt-out provided it cannot then include a partial opt-out, the opt-out will be locked in for three consecutive years, and it must include the RBDC opt-out adder percentage in its obligation. *Id*.

Speaking to future resource adequacy construct changes, the Staff reports that MISO has recently filed or is currently working on FERC filings to address challenges related to demand side resources and that MISO intends to implement enhanced resource adequacy risk modeling and a Direct Loss-of-Load (DLOL) accreditation methodology beginning in planning year 2028/2029. Staff Report, p. 12 (citing FERC Docket No. ER24-1638-000 (application filed March 28, 2024)). Starting with the 2025/2026 PY, MISO has committed to publishing indicative accreditation results based on the DLOL methodology prior to each PRA. The Staff explains that these proposed reforms will align the PRMR with accreditation of all resource classes but given the ongoing work, the indicative PRMR values under DLOL are not yet available. The Staff recounts that several LSEs asked whether DLOL accreditation should be used in this instant capacity demonstration case since the demonstration year aligns with the first year of DLOL implementation (2025/2026 PY). The Staff recommends that LSEs follow the prompt-year MISO adequacy resource construct and also recommends that the Commission determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement these changes prior to MISO's tariff changes effective in PY 2028/2029.

For MISO Zone 7, the Staff provides a table showing the annual MISO LOLE report data, as well as another table showing a comparison of LRZ 7 aggregated resources demonstrated plus known undemonstrated resources likely to still be available for each season in PY 2028/2029 and

MISO's resource adequacy requirements for PY 2025/2026. *Id*., pp. 13-15. With the caveat that its findings are based on projections that are subject to change, the Staff concludes that Zone 7 has a surplus of resources compared to the projected LCR for all four seasons. Specifically, Zone 7's summer PRMR is 21,228 zonal resources credits (ZRCs) and the LCR is 19,681 ZRCs. The total LRZ 7 resources offered in the PRA for the summer season in the prompt year is 20,884 ZRCs, which exceeds the anticipated LCR by 2,203 ZRCs but falls short of the zone's portion of PRMR. *Id*., p. 16. The zone relied on 785.5 ZRCs of external resources to meet its resource adequacy requirement target. *Id*.

For the interim years, the Staff Report contends that again, while subject to change, LRZ 7 has a capacity surplus for both years compared to the projected LCRs. The Staff notes that the capacity margin appears tight in 2026/2027 across all four seasons with the tightest capacity position in the fall season. *Id*., pp. 16-17.

As to Zone 2, which encompasses most of Michigan's Upper Peninsula and parts of Wisconsin, the Staff notes that MISO does not define MW capacity import or export limits between states within the same MISO zone and therefore, the data available to the Staff is not comprehensive enough to project a zonal capacity position for Michigan's Zone 2 similar to Zone 7. However, the Staff was able to conclude that: (1) all Michigan LSEs in Zone 2 demonstrated sufficient capacity resources, and (2) the 2024 MISO PRA results indicated an installed capacity surplus in PY 2024/2025. The Staff also states that Zone 2 has CILs of 4,370 MW in summer; 6,537 MW in fall; 6,522 MW in winter; and 6,439 MW in spring. *Id*., p. 17.

Turning to Zone 1, which includes a small fraction of Michigan's Upper Peninsula, the Staff reports that all Zone 1 LSEs demonstrated sufficient capacity obligations for the compliance year and that the 2025/2026 MISO PRA shows sufficient capacity for each season in PY 2025/2026, adding that Zone 1 relied on a small amount of imports to meet its resource adequacy target in winter and spring. *Id*., p. 17.

For Michigan LSEs serving load within PJM, the Staff notes that only a few LSEs in Michigan serve load within the PJM territory but that these LSEs are still subject to the capacity requirements of Section 6w. LSEs in PJM must meet capacity obligations through participation in PJM's reliability pricing model base residual auction (BRA) or through PJM's fixed resource requirement (FRR) plan. I&M, the largest Michigan-serving LSE in PJM, uses the FRR and indicates in the instant capacity demonstration that it plans to continue to do so. The Staff Report includes a table presenting a summary of PJM's capacity demonstration, and the Staff states that all PJM LSEs have sufficient capacity and that it expects all PJM LSEs to continue to meet their capacity obligations with continued monitoring by the Staff. Staff Report, p. 18.

The Staff also notes that I&M's customer choice cap was reset to 10% on February 1, 2019, pursuant to MCL 460.10a(1)(c) and the July 12, 2017 order in Case No. U-16090 (July 12 order). July 12 order, p. 3. I&M is responsible for providing capacity for its choice program, but if its suppliers opt to self-supply capacity, the company will need to include this in its FRR plan. Per the Staff Report, NERC projects PJM to have sufficient electric supply and categorizes PJM as having an elevated risk level post 2026, with resource additions not keeping up with generator retirements and demand growth, and with winter replacing summer as the higher risk period because of generator performance and fuel supply issues. Lastly, the Staff notes delays in PJM's BRA schedule due to pending decisions from FERC related to the capacity auction. The Staff Report also provides the current BRA schedule, which is scheduled to take place every six months until the schedule is no longer delayed. Staff Report, pp. 18-19.

In compliance with the Commission's request in the September 15 order, the Staff provides a table in the report identifying the capacity by type for each individual electric provider (without revealing the provider's identity) with a breakdown for each provider included as Appendix A to the Staff Report. The table describes the supplier type and the percentage of their demonstrated capacity that is owned; derived from demand response (DR), a power purchase agreement, or ZRC contract; or acquired at auction. Staff Report, pp. 19-20.

Explaining DR as an optional source of capacity, the Staff describes DR as having a prominent role in LSEs' integrated resource plan (IRP) filings and the Staff's obligation to complete a statewide study of DR potential in Michigan every five years. The Staff states that Consumers and DTE Electric included DR in their respective IRP filings and capacity demonstrations and that the Staff will continue to monitor Consumers' and DTE Electric's DR as well as DR use across Michigan. *Id*., p. 20.

Noting the Commission's affirmation of an AES' ability to offer DR programs through curtailment service providers or third-party aggregators, the Staff states that it is aware of 85 ZRCs of DR offered into the 2025 MISO capacity market. The Staff continues to collaborate to ensure that aggregated DR load modification is accounted for when dispatched on MISO's coincident peak and to monitor FERC Order 2222[8] discussions. *Id*., p. 21.

As to ZRC contracts, the Staff recommends that forward ZRC contracts be used for capacity demonstration purposes to specify delivery of the ZRCs in the MISO Module E Capacity Tracking (MECT) tool prior to the applicable PRA auction. There was an increase in the

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[8] *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 172 FERC ¶ 61,247 (September 17, 2020). FERC issued subsequent versions of FERC Order 2222, namely FERC Order 2222-A and FERC Order 2222-B. *See*, 174 FERC ¶ 61,197 (March 18, 2021) and 175 FERC ¶ 61,227 (June 17, 2021), respectively.

percentage of ZRC contracts utilized this year by utilities, municipal utilities, and cooperatives compared to last year's capacity demonstration. The Staff highlights the following:

> An important thing to note is that ZRCs are defined in MISO's tariff and are created in the prompt year when UCAP [unforced capacity] for supply-side and demand-side resources are converted into ZRCs in the MISO MECT. ZRCs for any year further out than the prompt year are projected and don't become ZRCs until the prompt year. ZRCs are fungible products that can be sold or transferred, and in some cases, sold more than once. The characteristics of ZRCs allow for them to be easily traded and tracked within the MISO MECT. MISO has a view into the source and transfers of those ZRCs that occur prior to the PRA in the prompt year, and those ZRC transfers are audited by Staff as a secondary check on the ZRC contracts utilized in the capacity demonstrations.

Staff Report, p. 21.

Following a brief explanation of its process for accounting for AES load switching, which was made more complex with the change to the seasonal construct, the Staff states that it continues to see an increase in load switching among LSEs. *Id*., pp. 21-22. The Staff recommends that LSEs that include load switching information in their filing include it within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. The Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their filings, enabling the Staff to easily cross-reference that the load is being accounted for.

Lastly, the Staff includes a discussion of capacity retirements and additions, stating that NERC's 2024 Long Term Reliability Assessment shows added resource capacity on the Bulk Power System (BPS) falling short of industry projections the year prior, demonstrating an over-projection of natural gas, solar, and wind resources, and giving evidence to project delays. Additionally, the Lawrence Berkeley National Laboratory's April 2024 interconnection queue study showed that only 19% of the projects (and just 14% of their capacity) that submitted interconnection requests from 2000 to 2018 reached commercial operations by the end of 2023. *Id.*, p. 22. Because of interconnection backlog issues, the Staff notes that some RTOs have taken steps to address these issues including PJM's Reliability Resource Initiative, both PJM's and MISO's work to reduce queue cycle times through automation, and MISO's Expedited Resource Addition Study (ERAS) process.[9] The Staff conveys that Michigan continues to follow national trends showing a tightening capacity position due to scheduled retirements outpacing replacement capacity buildout. The Staff notes that it met with LSEs to discuss their capacity concerns and explains that various factors could cause delays for new capacity additions, namely broad economic factors such as supply chain constraints, labor shortages, high component prices, and delays associated with obtaining permitting, regulatory approval, or interconnection queue delays. Per the Staff:

> The issue may be further exacerbated should demand increase faster than expected due to unanticipated loads such as data centers, as well as electrification of the building and transportation sectors. Staff has noted a significant number of planned resources used as demonstrated capacity in this case and recent previous cases that have not come to fruition in the demonstration year as planned, with estimates in the range of 900-1000 MW/year removed from the list of planned resources due to delays or cancellations. There are many instances of this occurring with IRP-identified resources, consequently Staff met with both large investor-owned utilities to discuss this issue in depth and determine what actions can be taken to overcome the delays. One of these utilities indicated they are in the process of quantifying project delays and terminations, and early estimates showed an average delay of ~1.5 years past Commercial Operation Date (COD) and a project failure rate greater than 25%.

[9] At the time the Staff Report was filed, MISO's ERAS process was pending approval before FERC. Following an initial rejection by FERC on May 16, 2025, and subsequent revisions to its ERAS proposal by MISO, FERC approved MISO's revised filing on July 21, 2025, in FERC Docket No. ER25-2454- 000, with the condition that MISO make a compliance filing by August 20, 2025, reflecting revised tariff language previously submitted by MISO. *See*, *Order Accepting Tariff Revisions, Subject to Condition*, 192 FERC ¶ 61,064 (July 21, 2025) (July 21 FERC order). FERC approved the ERAS tariff effective August 6, 2025. *See*, July 21 order, pp. 98, 135.

Staff Report, pp. 22-23. The Staff adds that some capacity from the Palisades Nuclear Power Plant was included in Michigan's capacity demonstration for Spring 2026 (the remainder of the capacity is being contracted by an LSE in Indiana). The Palisades capacity would provide resource adequacy benefits to Zone 7 and be counted towards meeting the LCR for Zone 7.[10] Staff Report, p. 23.

In its conclusions and recommendations, the Staff repeats that all LSEs have complied with their capacity demonstration obligations pursuant to Section 6w and expresses its appreciation for the cooperation of all LSEs. *Id*., pp. 20-21. The Staff then presents a summary of its recommendations:

1. Staff recommends the Commission continue to direct all LSEs to include updated prompt year and interim year capacity obligation and resource information in future filings.

2. Staff recommends the Commission direct all LSEs to provide [an] MECT screenshot of their prompt load obligations (PRMR/PLC [peak load contribution]) to facilitate the Storage Target calculation used to comply with Public Act 235.

3. The Commission should determine a timeline to implement MISO's DLOL accreditation changes into the state capacity demonstration process if it deems it necessary to implement prior to MISO tariff changes effective PY 2028-29.

4. Staff recommends that filing entities who include load switching information in their filing include it within the Contracted Resources [section] on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Staff also recommends that both the losing and the gaining suppliers have copies of the load switching affidavits in each of their

[10] At the time of the filing of the Staff Report, the re-start of the Palisades Nuclear Plant was pending approval before the U.S. Nuclear Regulatory Commission (NRC). On July 24, 2025, NRC granted some key approvals necessary to the re-start of the Palisades Nuclear Plant. Namely, NRC approved six exemptions from the requirements of Title 10 of the Code of Federal Regulations (10 CFR) Section 50.82(a)(2), "Termination of license," concerning the prohibition against operating the reactor and emplacing fuel into the reactor vessel for the Palisades Nuclear Plant. The exemptions will be effective on August 25, 2025. *See*, NRC Docket No. 50-255; NRC-2025-0346 (July 24, 2025). However, other licensing actions remain pending before NRC as of the date of this order.

filings, so Staff is able to cross check that the load is being accounted for.

Staff Report, p. 23.

Discussion

To begin, the Commission appreciates the efforts of the Staff in obtaining and analyzing the capacity information needed for this year's capacity demonstrations and for drafting the Staff Report as well as the filing of the 2025 Statewide Energy Storage Target Calculation. The Commission also appreciates the cooperation of all Michigan LSEs for their capacity demonstration filings.

Before addressing the Staff Report, the Commission takes this opportunity to note an update relevant to the state's capacity outlook that occurred after the filing of the Staff Report. On May 23, 2025, the U.S. Department of Energy (DOE) issued an emergency order to MISO in coordination with Consumers, pursuant to Section 202(c) of the Federal Power Act, to ensure that the J.H. Campbell Power Plant (Campbell Plant) in West Olive, Michigan remains available for operation to minimize any potential generation shortfall that could lead to unnecessary power outages. *See*, DOE, Order No. 202-25-3 (May 23, 2025). The Campbell Plant was scheduled to cease operations on May 31, 2025. The Commission notes that the retirement of the Campbell Plant was planned for in Consumers' 2022 IRP and replacement capacity has been procured through the purchase of a natural gas fired power plant in 2023, extending the retirement dates for two other fossil fuel units, increasing demand side resources such as DR and energy waste reduction, and adding renewable energy and energy storage resources through 2040. *See*, June 23, 2022 order in Case No. U-21090, pp. 5, 95 (approving a settlement agreement resolving all issues in the case); *see also*, *id*., Exhibit A, pp. 4-5. Consumers also filed its capacity demonstration on February 24, 2025, prior to the issuance of the DOE's emergency order and demonstrated sufficient capacity for the compliance PY. *See*, Case No. U-21775, filing # U-21775-0012; *see also*, Staff Report, pp. 6, 23.

Turning to the Staff Report, the Commission accepts the Staff Report's findings regarding resource adequacy in MISO LRZs 1, 2, and 7 and in the PJM market, the capacity demonstrations made by the LSEs, and the 2025 Statewide Energy Storage Target Calculation. The Commission also accepts the Staff's filing of a memorandum in this docket on August 12, 2025, confirming its review of MSCPA's revised capacity demonstration filing indicating that MSCPA has secured the capacity necessary to satisfy its capacity obligation under Section 6w. The Commission finds that MSCPA has resolved its capacity shortage issue and has now complied with the requirements of Section 6w.

As noted in last year's capacity demonstration report, the Staff stated in this year's report that most LSEs included updates for the 2025/2026 PY through the 2027/2028 PY. For the upcoming capacity demonstration in Case No. U-21907, the Commission agrees with the Staff's recommendation for LSEs to continue providing this additional information and thus, directs LSEs to provide capacity resource data for the prompt year (2026/2027) and interim years (2027/2028 and 2028/2029) in addition to the compliance year (2029/2030) data. The additional data is to be included in the upcoming February 24, March 3, and March 17, 2026 capacity demonstration filings opened by this order in Case No. U-21907. The Staff shall then file its 2029/2030 PY capacity demonstration report in Case No. U-21907 no later than May 12, 2026.

Before addressing the Staff's recommendations, the Commission notes that in the Staff Report, the Staff described the DLOL accreditation and referenced MISO's application for approval of the revised tariff to establish DLOL accreditation that was filed with FERC on March 28, 2024. The Commission adds that on October 25, 2024, FERC approved MISO's proposed tariff revisions to establish the DLOL accreditation methodology. *See*, 189 FERC ¶ 61,065 (October 25, 2024). As the Staff indicated, MISO will implement the DLOL accreditation methodology in the 2028/2029 PY and is continuing its work to provide the PRMR values under the DLOL methodology. The Staff recommended that the Commission determine a timeline to implement MISO's DLOL accreditation changes into Michigan's capacity demonstration process if the Commission finds such action to be necessary prior to the effective date of the revised MISO tariff in 2028/2029. The Commission finds that establishing such a timeline is not necessary at this time given MISO's ongoing work to establish the PRMR values that will be used in the DLOL methodology. Therefore, the Commission will continue to monitor MISO's progress in this area and will revisit this issue as more information becomes available. At this time, the Commission agrees with the Staff's recommendation to LSEs for the instant capacity demonstration and for future demonstrations that they should follow the prompt-year MISO resource adequacy construct.

Turning to the Staff's other recommendations, the Commission finds these recommendations to be reasonable and necessary to provide the Commission with comprehensive information regarding an LSE's capacity position for the prompt, interim, and compliance years and to satisfy the requirements of Section 6w. Therefore, with the exception of the establishment of a timeline to implement DLOL into Michigan's capacity demonstration process, the Commission adopts the Staff's recommendations set forth in the Staff Report. *See*, Staff Report, p. 23.

With this order, the Commission also opens the Case No. U-21907 docket for the purpose of receiving next year's capacity demonstrations from required LSEs pursuant to Section 6w. As mentioned above, electric utilities required to file capacity demonstrations pursuant to Section 6w(8)(a) for the 2029/2030 PY shall make that filing no later than 5:00 p.m. (Eastern time (ET)) on February 24 and March 3, 2026 in Case No. U-21907. LSEs required to file capacity demonstrations pursuant to Section 6w(8)(b) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (ET) on March 17, 2026, in Case No. U-21907. Electric utilities and LSEs shall include in their respective filings capacity resource data for the prompt (2026/2027) and interim years (2027/2028 and 2028/2029) as well as the compliance year (2029/2030). All LSEs making required filings pursuant to Section 6w(8) shall utilize the Capacity Demonstration Filing Process and Requirements document, General Affidavit, and, as applicable, AES Load Switching Affidavit attached to this order as Exhibits A, B, and C, respectively. All filing LSEs shall also provide an MECT screenshot (or equivalent) of their prompt load obligations (PRMR/PLC) to facilitate the energy storage target calculation used to comply with Act 235. Lastly, LSEs who include load switching information in their capacity demonstration filing shall include such information within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Also, both the losing and the gaining suppliers in the load switching arrangement shall include copies of the AES Load Switching Affidavit, attached to this order as Exhibit C, in each of their capacity demonstration filings, enabling the Staff to easily cross-reference that the load is being accounted for.

THEREFORE, IT IS ORDERED that:

A. The Commission Staff's May 12, 2025 Capacity Demonstration Results Report and 2025 Statewide Energy Storage Target Calculation filed in Case No. U-21775 are accepted.

B. Electric utilities required to file capacity demonstrations pursuant to MCL 460.6w(8)(a) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (Eastern time) on February 24 and March 3, 2026, in Case No. U-21907, as described in this order and in the

Capacity Demonstration Filing Process and Requirements document attached to this order as Exhibit A. Load serving entities required to file capacity demonstrations pursuant to MCL 460.6w(8)(b) for the 2029/2030 planning year shall make that filing no later than 5:00 p.m. (Eastern time) on March 17, 2026, in Case No. U-21907. Electric utilities and load serving entities shall include in their respective filings capacity resource data for the prompt (2026/2027) and interim years (2027/2028 and 2028/2029) as well as the compliance year (2029/2030), as described in this order. Load serving entities required to file capacity demonstrations pursuant to MCL 460.6w(8) shall utilize the Capacity Demonstration Filing Process and Requirements document and General Affidavit attached to this order as Exhibits A and B, respectively.

C. The Commission Staff shall file a report analyzing the sufficiency of the capacity demonstrations for the 2029/2030 planning year no later than 5:00 p.m. (Eastern time) on May 12, 2026, in Case No. U-21907.

D. The Commission Staff shall file in Case No. U-21907 the update to the energy storage capacity amounts for electric providers using the Statewide Energy Storage Target Calculation within 30 days after the completion of the capacity demonstrations for the 2029/2030 planning year required under MCL 460.6w.

E. Any load serving entity required to file capacity demonstrations pursuant to MCL 460.6w(8) for the 2029/2030 planning year shall provide a Module E Capacity Tracking screenshot (or equivalent) of its respective prompt load obligations (planning reserve margin requirement/peak load contribution) to facilitate the energy storage target calculation used to comply with Public Act 235 of 2023, MCL 460.1001 *et seq*., as described in this order.

F. Any load serving entity that includes load switching information in its capacity demonstration filing shall include it within the Contracted Resources section on the spreadsheet templates provided for the capacity demonstration for the demonstration years as well as the interim years. Both the losing and the gaining suppliers in the load switching arrangement shall include copies of the AES Load Switching Affidavit, attached to this order as Exhibit C, in their respective capacity demonstration filings.

G. The docket in Case No. U-21775 is closed, and the docket in Case No. U-21907 is opened for the purpose of receiving the capacity demonstration filings for the 2029/2030 planning year and the Statewide Energy Storage Target Calculations to be filed by the Commission Staff.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Shaquila Myers, Commissioner

By its action of August 21, 2025.

Lisa Felice, Executive Secretary

CAPACITY DEMONSTRATION PROCESS AND REQUIREMENTS

The Michigan Public Service Commission (MPSC or Commission) will open a new docket annually for capacity demonstrations filings. The Commission order opening the capacity demonstration docket will provide updated requirements for load serving entities (LSE) to follow in making demonstrations. The capacity demonstration filings shall include four years of load obligations and capacity resources. The capacity demonstration for year four will be used to determine if the LSE has met its capacity obligations, while the data filed for years one through three will be used for informational purposes only. For the demonstration year, each LSE's capacity obligation will be equal to its most recent capacity obligation as specified by the applicable Independent System Operator (ISO).

For LSEs in the Midwest Independent System Operator (MISO), the capacity obligation will be based on the MISO seasonal resource adequacy construct. LSEs will be obligated to demonstrate enough capacity (owned or contracted) to meet the LSE's capacity obligation for each season. The specific capacity obligation for each season will be the LSE's prompt year (upcoming year) Initial Planning Reserve Margin Requirement (PRMR) for each respective season. According to the MISO Tariff, the Peak Load Contribution (PLC) for each retail customer in the Electrical Distribution Company's (EDC) area – including the EDC's own LSE – includes the retail customer's demand at the time of MISO's peak demand for each prior season, transmission losses, planning reserve margin %, and an adjustment factor for the prompt year seasonal EDC forecasts. The Initial PRMR for each LSE for a season consists of the sum of the PLCs for the retail customers assigned to that LSE[1]. MISO LSEs will be obligated to demonstrate enough capacity for the demonstration year to meet its prompt year Initial PRMR MISO requirements[2].

For LSEs in PJM, the capacity obligation will be based on the PJM Reliability Pricing Model (RPM). LSEs in the PJM service territory can meet their Independent System Operator capacity obligations either through participation in PJM's (RPM) Base Residual Auction (BRA) or through PJM's Fixed Resource Requirement (FRR) capacity plan. The timing of PJM LSEs capacity demonstrations to the Commission will remain the same as those expected of MISO LSEs; however, PJM LSEs will be allowed to file an amended capacity demonstration two weeks after the completion of the BRA. The capacity demonstration should include the FRR capacity plan or BRA results. Meeting PJM's capacity obligations, including any applicable Percentage Internal Resources Required for the delivery year will constitute a satisfactory demonstration, and the demonstrating LSE should provide evidence that it has met PJM's capacity obligations.

LSEs shall provide documentation to Staff verifying the applicable capacity obligation from the LSEs ISO.[3]

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[1] The Initial PRMR determination for all LSEs, including the EDC's own LSE, shall be made according to the MISO tariff. See MISO tariff Module E-1, Section 69A.1.1.e and Section 69A.1.2.1.b.

[2] LSEs that develop their load forecasts based on forward year values may use these values instead of prompt year values for capacity demonstration requirements if they are higher than the prompt year requirements. LSEs obligations should not be reduced to an amount less then the prompt year requirements due to declining forecasts for forward years.

[3] Documentation could be included in the filing or shared in a meeting (virtual or in person) with Staff, similar to how resource contracts are shared.

Individual Locational Requirement

The individual locational requirement adopted by the MPSC in the June 28, 2018 Order in Case No. U-18444 remains stayed[4]. There is currently no individual locational requirement applicable to capacity demonstration filings.

Resource Demonstrations

As a default, resources shall be accredited as they are in their respective ISO.

For MISO LSEs, resources should be counted at the same seasonal accredited capacity value that they will receive in the prompt year for each season. If prompt year capacity value is not finalized, resources shall be counted at the seasonal accredited capacity level from the most recent information available.

For PJM LSEs, resources shall be based on the credited UCAP capacity value that they are credited within the PJM RPM for the demonstration year.

New resources (in either ISO) shall receive capacity credit they would reasonably receive within the various resource adequacy constructs. LSEs should provide documentation supporting the capacity accreditation of new resources.

Resource accreditation may vary from ISO accreditation if the LSE is able to provide reasonable support that the resource will be valued at a different capacity amount when the demonstration year becomes the delivery year. These variations will be evaluated by Staff on a case-by-case basis.

The minimum acceptable support for all resources submitted as part of a capacity demonstration is based upon the type of resource and is outlined below. Statements to achieve/maintain resources do not prohibit an LSE from entering into a future transaction to sell surplus capacity provided that the same capacity is not used by another Michigan LSE as part of its capacity demonstration filing for the same planning year.

Existing Generation (Owned)

The minimum acceptable support for existing generation that is included in a capacity demonstration include:

1) An affidavit from an officer of the company claiming ownership of the unit(s), including a commitment of the unit(s) to LSE load in the applicable demonstration year,
2) A copy of the existing resource qualification of the unit(s) from the applicable ISO, such as a MISO Module E Capacity Tracking Tool (MECT) screenshot in the MISO region, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

[4] Stayed by the September 13, 2018 Order in Case No. U-18444.

Existing Demand Response or Energy Efficiency Resources
(that have not been netted against load)

The minimum acceptable support for existing demand response resources or energy efficiency resources that have not already been netted against load include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to maintain at least that same level of resources four years forward,
2) A copy of the existing resource qualification of the resource(s) from the applicable ISO, such as a MISO MECT screenshot, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

New or Upgraded Generation (Owned)

The minimum acceptable support for proposed new generation include:

1) An affidavit from an officer of the company outlining the plans for the new generation including resources outlined in the utilities' most recent IRP,[5] milestones such as planned in-service date, expected regulatory approval date(s), planned date to enter the generator interconnection queue, expected date for generator interconnection agreement, construction timeline, etc.,
2) Documentation supporting the expected resource qualification from the ISO for the new unit(s), and;
3) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

For new generation submitted as part of a capacity demonstration, the LSE shall update and submit the above information on an annual basis with each subsequent capacity demonstration until the unit(s) are in service.

New Demand Response or Energy Efficiency Resources
(that have not been netted against load)

The minimum acceptable support for new demand response resources or energy efficiency resources that have not already been netted against load included in a capacity demonstration include:

1) An affidavit from an officer of the company outlining the plans for the resource(s), including a commitment to achieve and/or maintain at least that same level of resources four years forward,
2) Evidence that the customer's distribution utility has been notified of specific customers participating in the resource,
3) Specific plans to have the resource(s) qualified by the independent system operator, and;

[5] If including resources included in the utility's most recent approved IRP, the utility shall also file a status update in the next capacity demonstration docket.

4) If there are Michigan retail tariffs or customer contracts associated with the resources, copies shall be provided.

For new demand response or energy efficiency resources submitted as part of a capacity demonstration, the LSE shall update and submit the above information on an annual basis with each subsequent capacity demonstration until the resource(s) are in service. Final qualification / approval from the independent system operator should be submitted in a subsequent demonstration.

Capacity Contract

The minimum acceptable support for capacity contracts with existing generation include:

1) An affidavit from an officer of the company including a copy of the contract that specifies the unit(s) or pool of generation that is the source of the contract, including the location of the unit(s) or pool. The affidavit shall include a commitment to maintain the contract four years forward regardless of any early out clauses in the contract, and;
2) A copy of the existing resource qualification of the unit(s) or pool from the applicable ISO, such as a MISO MECT screenshot.

Forward ZRC contracts

For MISO LSEs that use ZRC contracts to meet capacity obligations. The minimum acceptable support for forward ZRC contracts includes an affidavit from an officer of the company including a copy of the contract that specifies the zonal location of the ZRCs. The affidavit shall include a commitment to maintain the contract four years forward regardless of any early-out clauses in the contract. A forward ZRC contract that does not specify the zonal location of the ZRCs will be deemed insufficient towards meeting any portion of a locational requirement, unless the LSE provides other alternative support for the location of the ZRCs.

Any LSE that utilized a ZRC contract as part of their previous capacity demonstrations must provide prompt-year ZRC transfer documentation (such as a MECT Module E screenshot) or provide Staff with the ability to confidentially review ZRC transfers in person at the Commission office.

If the Commission were to implement an individual locational requirement, ZRC contracts submitted in an LSE capacity demonstration to meet this forward locational requirement must clearly designate that the resources are coming from the applicable zone. LSEs must provide evidence to support this. For resources currently located outside of the LSE’s zone that will (by the demonstration year) count towards meeting the Local Clearing Requirement of the LSE’s zone should be supported by evidence provided by the demonstration LSE. Existing contracts specifically with resources outside of an LSE’s MISO zone will count towards meeting forward locational requirements if they are for a period of at least twenty years and the contracts were entered into prior to MISO’s implementation of local resource zones on June 1, 2013.

Aggregated EERs, Aggregated Storage, Aggregated DERs

The minimum acceptable support for aggregated energy efficiency resources (EERs), aggregated storage, and aggregated distributed energy resources (DERs) include:

1) An affidavit from an officer of the company outlining the resource(s), including a commitment to achieve and/or maintain at least that same level of resource(s) four years forward,
2) Documentation from the ISO showing resource accreditation in the prompt-year for the resource(s), such as a MISO MECT screenshot, and;
3) If there are Michigan retail tariffs or customer contracts associated with the resource(s), copies shall be provided.

MISO PRA Purchases

The amount of ZRCs planned to be purchased through the MISO Planning Resource Auction (PRA) process[6] that will be deemed prudent in an approved capacity demonstration will be limited to 5% of the LSE's total requirement. A capacity demonstration filed by an LSE that includes a plan to purchase ZRCs in the PRA four years in the future in excess of 5% will not constitute a demonstration that the LSE owns or has contracted resources to meet its future capacity obligations, unless those ZRCs are tied to specific identified resources that are committed to be offered in the PRA, by contract, on behalf of the LSE for the applicable planning year.

Interim Years[7]

Once the Commission has determined that the capacity demonstration made by an LSE is sufficient, it shall not be re-litigated or "trued-up" in the interim years. If, subsequent to its initial satisfactory capacity demonstration, an LSE experiences an unforeseen outage at one of its generation assets, or has variation in its total load obligations, these matters will be settled in the capacity auctions of the respective ISO. The LSE's initial capacity demonstration will not be re-examined to reconcile projected interim year load obligations or generating resource capacity ratings with actual values that are experienced in that interim year.

Additional Considerations for Capacity Demonstrations

Other types of documentation submitted as part of a capacity demonstration will be evaluated on a case-by-case basis. Because some of the documentation that is required to be filed in these proceedings is commercially sensitive, competitive information, it shall continue to be treated in a confidential manner, as has been done in the past. The Staff shall file a memo in the docket as directed by the Commission, outlining its findings from the demonstration filings, including a listing of any entities whose demonstration, in Staff's opinion, was insufficient.

In the case where a demonstration filing is deemed insufficient by Staff, Staff would recommend that the Commission open a contested case docket, whereby the LSE in question could attempt to prove that

[6] Since 2012, LSEs do not literally purchase ZRCs in the PRA. The current terminology in the MISO tariff of "purchase through the PRA process" means that MISO is charging an LSE more for capacity to satisfy the LSE's PRMR than it is paying the LSE for ZRCs submitted into the PRA.
[7] Year 1 (prompt year), Year 2, and Year 3 of the demonstration.

its capacity demonstration should be deemed acceptable. The outcome of that case would be a Commission order potentially authorizing Statewide Reliability Mechanism capacity charges to Retail Open Access customer load as well as a respective increase in capacity obligations assigned to the incumbent utility as the Provider of Last Resort for capacity service. Any contested demonstration cases will be opened as soon as practicable following the issuance of the Staff memo and be completed within six months.

If an LSE has met the capacity demonstration requirements, no contested case will be opened, and no further action will be taken regarding any capacity demonstration that has been deemed sufficient by Staff and accepted by the Commission.

Filing Timeline

Section 6w of Public Act 341 of 2016 gives specific filing dates for LSEs to make capacity demonstrations but gives the Commission the authority to adjust the dates if needed to properly align with the ISO procedures and requirements. The timeline below better aligns with the MISO PRA, allowing capacity obligations and resource accreditation to better match the values used by MISO in the prompt year.

For Demonstration Year 2029/2030	
Docket Opened by Commission	Summer/Fall 2025
Larger Investor-Owned Electric Utilities[8] Filing Due	February 24th, 2026
Smaller Investor-Owned Electric Utilities[9] Filing Due	March 3, 2026
All Other LSEs Filing Due	March 17th, 2026
Staff Report on Capacity Demonstration Findings	May 12th, 2026
Commission Order	Summer/Fall 2026

The specific filing dates will be established by the Commission in each subsequent capacity demonstration docket and will generally align with the filing timeline above. LSEs will be allowed to supplement filings after the filing date and prior to Staff's report, if changes at the ISO level, for capacity obligation or resource accreditation, necessitate updated filings[10].

Demonstration Format

In addition to all of the items outlined above, Staff shall provide updated capacity demonstration documents (Reporting Templates and Sample Affidavits)[11] to be utilized by each LSE when filing its demonstration.

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[8] A large investor-owned utility is considered to be an electric utility with one million or more customers.
[9] A smaller investor-owned utility is considered to be an electric utility with less than one million customers.
[10] In this event, LSEs should notify Staff as soon as practicable that a supplemental filing is imminent and make the filing with sufficient time to allow Staff to review and incorporate those changes into the report.
[11] Documents will be posted to the MPSC Capacity Demonstration webpage (https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/capacity-demonstration).

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter, on the Commission's own motion, to open a docket for load serving entities in Michigan to file their capacity demonstrations as required by MCL 460.6w.	)	Case No. U-21775

AFFIDAVIT OF [Name of Company Officer]

STATE OF MICHIGAN

COUNTY OF (County name)

[NAME of Company Officer], being duly sworn, states that the following information and attached exhibits are true and accurate to the best of his/her reasonable knowledge and belief, regarding [the company's] satisfaction of its Michigan capacity demonstration requirements:

1. [Description of role and responsibilities within company]

2. [Overview of company]

3. [Overview of filing – if applicable for LSE, describe the load in each RTO, each local resource zone, and each service territory]

4. **Existing Generation - Owned** [Claim ownership of the unit(s), including a commitment of the unit(s) to LSE load in the applicable Michigan zone four years forward. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

5. **Existing Demand Response or Energy Efficiency Resources (Not Netted Against Load)** [Outline the resource(s), including a commitment to maintain at least that same level of resources four years forward. If an AES has a LMR, describe how the transmission losses are applied in each service territory. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

6. **Existing Demand Response or Energy Efficiency Resources (Netted Against Load)** [Outline what is netted against load, current programs, and how big these programs are.]

7. **New or Upgraded Generation – Owned** [Outline the detailed plans for the new generation including milestones such as planned in-service date, expected regulatory approval date(s), planned date to enter the MISO generator interconnection queue, expected date for MISO

generator interconnection agreement, construction timeline, etc. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

8. **New Demand Response or Energy Efficiency Resources (Not Netted Against Load)** [Outline the plans for the resource(s), including a commitment to achieve and/or maintain at least that same level of resources four years forward. If an AES has a LMR, describe how the transmission losses are applied in each service territory. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

9. **Existing Generation (Capacity Contract)** [Include a copy of the contract that specifies the unit(s) or pool of generation that is the source of the contract, including the location of the unit(s) or pool (can be filed confidentially) and state commitment to maintain the contract four years forward regardless of any early out clauses in the contract. In lieu of filing a copy of the contract(s), provide information set forth in the MPSC Order on Rehearing in Case No. U-18197, dated November 21, 2017, for Staff/Commission contract review. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

10. **Forward ZRC Contracts** [Include a copy of the contract that specifies the zonal locations of the ZRCs. The affidavit should include a commitment to maintain the contract four years forward regardless of any early out clauses in the contract. In lieu of filing a copy of the contract(s), provide information set forth in the MPSC Order on Rehearing in Case No. U-18197, dated November 21, 2017, for Staff/Commission contract review. (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)]

11. **Planning Reserve Auction Purchases** (If this does not apply to your LSE, state that it is not applicable in planning year 20**-20**.)

____
NAME

SUBSCRIBED AND SWORN TO BEFORE ME on the _____ day of [month], [year].

____
Notary Public

My Commission Expires: _____________

ALTERNATIVE ELECTRIC SUPPLIER LOAD SWITCHING AFFIDAVIT

State of __________

County of _________

[NAME], [title] of (“Receiving Supplier”), upon oath deposes and states that the following information is true and accurate to the best of his/her reasonable knowledge and belief:

(“Receiving Supplier”) will assume responsibility for an additional ______ MW in capacity peak load contribution values (“Additional PLC Value”) associated with migrating customer load in _______ service territory for Planning Year 20** - 20**, over and above (“Receiving Supplier’s”) capacity demonstration obligation. (“Receiving Supplier”) understands that the customer load reflected in this Additional PLC Value is currently the responsibility of (“Losing Supplier”).

This Affidavit is being provided at the behest of the Michigan Public Service Commission Staff, in furtherance of implementation of Section 6w of Public Act 341.

____
NAME

SUBSCRIBED AND SWORN TO BEFORE ME on the _____ day of [month], [year].

____
Notary Public

My Commission Expires: ____________

PROOF OF SERVICE

STATE OF MICHIGAN)

Case No. U-21775 *et al.*

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on August 21, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna J. Brown

Brianna Brown

Subscribed and sworn to before me
this 21st day of August 2025.

Angela P. Sanderson

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

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Attachment KK

MI-Regional-Haze-SIP-Supplement-2021

SUPPLEMENT TO
MICHIGAN'S AUGUST 23, 2021,
REGIONAL HAZE STATE IMPLEMENTATION PLAN REVISION
FOR THE SECOND PLANNING PERIOD

Michigan Department of Environment, Great Lakes, and Energy
Air Quality Division
P.O. Box 30260
Lansing, Michigan 48909-7760
https://www.michigan.gov/air

[Public Notice Draft for 30-day Public Comment Period]

March 2025

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EXECUTIVE SUMMARY

The federal Clean Air Act (CAA) sections 169A and B [42 United States Code (U.S.C.), Sections 7491 and 7492] require the protection of visibility in 156 mandatory Federal Class I areas (Class I areas). These areas consist of all international parks, national wilderness areas and national memorial parks exceeding 5,000 acres, and national parks exceeding 6,000 acres that were in existence on August 7, 1977, for which visibility was found to be an important value, as stated in CAA section 162(a) [42 U.S.C. 7472(a)]. The United States Environmental Protection Agency's (USEPA) 1999 Regional Haze Rule, Title 40 of the Code of Federal Regulations (CFR) 51.308, requires states to develop and implement State Implementation Plan (SIP) revisions on a periodic basis to reduce visibility impairment, known as regional haze, resulting from "manmade air pollution." SIP revisions for the second planning period were due July 31, 2021. *See* 82 Federal Register (FR) 3078, January 10, 2017.

On August 23, 2021, the Michigan Department of Environment, Great Lakes, and Energy (formerly known as the Department of Environmental Quality, collectively referred to as "EGLE" in this document) submitted to the USEPA its Regional Haze SIP revision for the second implementation period, covering the 10-year period of 2019 to 2028. (Michigan's August 23, 2021, Regional Haze SIP submittal is included in full as Appendix 1 to this SIP Supplement). This document is a supplement to the Regional Haze SIP submitted to the USEPA in August 2021. The primary purpose is to expand on the four-factor analysis included in the original SIP submittal. It also addresses further the emission reductions that have occurred as well as those expected in the future from the shutdown of electric generation units (EGU) throughout the state of Michigan. The shutdown information is a key component to understanding the continued reduction in sulfur dioxide (SO_2) and oxides of nitrogen (NO_X) emissions in Michigan that improve visibility at Michigan's two Class I areas addressed in this SIP. These reductions also positively impact visibility in downwind regions of the country. The appendices contain details of each EGU that has shut down in recent years and those planning on shutting down in the relatively near future. This detail on emission reductions in the state expands on Michigan's position taken in the 2021 Regional Haze SIP submittal that visibility continues to improve and that additional emission reductions from the sources reviewed for the four-factor analysis would have little impact on already-improving visibility compared to the many reductions from EGUs.

Some other considerations in this supplement address USEPA guidance and input that may not have been addressed in the August 2021 SIP submittal. On July 8, 2021, approximately seven weeks before EGLE submitted its 2021 Regional Haze SIP revision, the USEPA released a memo entitled "Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period" (2021 Clarifications Memo)[1], describing clarifications to the Regional Haze Rule and USEPA's "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period," published on August 20, 2019 (2019 Regional Haze Guidance)[2]. Because of the timing of the memo and the July 31, 2021, deadline for SIP revisions contained in the Regional Haze Rule, EGLE did not have a timely opportunity to fully assess the clarifications, revise its SIP submittal accordingly, or provide a second 60-day Federal Land Management (FLM) consultation period and public comment period.

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[1] Clarifications Regarding Regional Haze State Implementation Plans for the Second Implementation Period. USEPA Office of Air Quality Planning and Standards, Research Triangle Park (July 8, 2021). (2021 Clarifications Memo) https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf.

[2] Guidance on Regional Haze State Implementation Plans for the Second Implementation Period. https://www.epa.gov/visibility/guidance-regional-haze-state-implementation-plans-second-implementation-period EPA Office of Air Quality Planning and Standards, Research Triangle Park (August 20, 2019).

This SIP supplement also provides additional information and justification to ensure Michigan achieves its reasonable progress goals for 2028 and meets the requirements as specified under 40 CFR 51.308(f). Coupled with Michigan's 2021 Regional Haze SIP submittal, this SIP supplement provides further evaluation of control measures and strategies as potential components of EGLE's Long-term Strategy (LTS) as required under 40 CFR 51.308(h)(4). The evaluation was conducted in accordance with the Regional Haze SIP development steps outlined in the USEPA's 2019 Regional Haze Guidance document outlined in the Table of Contents.

Overall, EGLE's LTS relies on on-the-books and on-the-way control measures that include, among other things, the retirements of 30 coal and fossil-fuel fired EGUs at 12 different power plants during the second implementation period. Based on the 2016 emissions inventory, the retirements that have already occurred during the second implementation period between 2018 and 2024 account for reductions in emissions of 17,417 tons per year (tpy) NO_X and 42,655 tpy SO_2. On the way are also the retirements of 3 more coal-fired EGUs required under a settlement agreement by May 31, 2025, representing additional reductions in emissions of 2,346 tpy NO_X and 12,850 tpy SO_2 based on the 2016 inventory. Together, these reductions represent a historically significant decrease in Michigan's statewide emissions by 30 percent NO_X and 65 percent SO_2 from all units in the second implementation period, with a sum, annual emissions in tons divided by distance in kilometers between a source and the nearest Class I area (Q/d) of 1.0 or greater. With still more on the way, 2 additional coal-fired EGUs will be retired under the same settlement agreement by May 31, 2031, representing additional reductions of 40 tpy NO_X and 58 tpy SO_2 in the third implementation period.

To summarize, this SIP supplement provides updates, additional information, and justification for:

- Determination of Affected Class I Areas
- Selection of Source for Analysis
- Confirmations of Source Retirements
- Effective Control Demonstrations
- Full Four-factor Analyses for Emission Units at Billerud Escanaba LLC, Graymont Western Lime, Inc., and Tilden Mining Company LC
- LTS and Control Measures Necessary to make Reasonable Progress
- Reasonable Progress Goals
- Progress Report

For this SIP supplement, EGLE facilitated a 60-day consultation period with the FLM as required by 51.308(i)(2) as well as an opportunity for public comment and hearing. EGLE made revisions based on comments received during the consultation and comment period, and EGLE's response to comments is included in the appendices.

EGLE is providing this SIP Supplement at this time fully aware that the USEPA became subject to a final action deadline set for May 30, 2025, for Michigan's Regional Haze SIP through a Federal Consent Decree that was entered on July 12, 2024, by the United States (U.S.) District Court for the District of Columbia. See *Sierra Club, et al. v. United States Environmental Protection Agency, et al.*, No. 1:23–cv–01744–JDB (U.S. District Court for the District of Columbia).

Together, Michigan's 2021 Regional Haze SIP Revision and this SIP Supplement address all required elements of 40 CFR 51.308(f) and demonstrate satisfactory progress toward the long-term visibility goals in the Regional Haze Rule and the CAA. This SIP does not include the relaxation of any existing requirements and therefore will not interfere with the attainment or maintenance of the National Ambient Air Quality Standards (NAAQS) in accordance with section 110(l) of the CAA.

1. Step 1: AMBIENT DATA ANALYSIS

Identify the 20 percent most anthropogenically impaired days and the 20 percent clearest days and determine baseline, current, and natural visibility conditions for each Class I area within the state. See 40 CFR 51.308(f)(1).

EGLE's ambient data analysis was provided in Section 2 of Michigan's 2021 Regional Haze SIP submittal, beginning on page 6. Michigan's August 23, 2021, Regional Haze SIP submittal is provided in full as Appendix 1 to this SIP Supplement.

2. Step 2: DETERMINATION OF AFFECTED CLASS I AREAS IN OTHER STATES

Determine which Class I area(s) in other states may be affected by the state's own emissions. See 40 CFR 51.308(f)(2)

The determination of affected Class I Areas is initially addressed in Section 2 of Michigan's 2021 Regional Haze SIP submittal, beginning on page 7 (*See* Appendix 1). Further elaboration is provided below.

To determine the impact on visibility at Class I areas from sources in Michigan for the second implementation period, EGLE relied upon modeling performed by the Lake Michigan Air Directors Consortium (LADCO). LADCO is the regional planning organization representing the states of Michigan, Illinois, Indiana, Minnesota, Ohio, and Wisconsin. LADCO used the Comprehensive Air Quality Model with extensions Particulate Matter Source Apportionment Tool (PSAT) for its analysis. LADCO tagged states and regions as well as individual point sources and inventory source groups to apportion emissions to states and regions. Then LADCO estimated relative visibility impacts in 2028 by projecting representative emissions inventories and known emission controls using 2011 and 2016 as base years. *See* Appendices 2 and 3: "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 – 2028 Planning Period: Technical Support Document and Supplemental Materials," June 17, 2021 (LADCO's 2021 Technical Support Document).

2.1 Updated Information for the Determination of Affected Class I Areas

Michigan's 2021 Regional Haze SIP submittal contained data on projected visibility in 2028 based on LADCO's modeling using a 2011 base year. Reflecting LADCO's more recent modeling for the 2028 projections with a 2016 base year, updated tables and figures appear in Step 6, below, to depict EGLE's 2028 reasonable progress goals for Isle Royale and Seney under the projected 2028 deciviews on the 20 percent most impaired and clearest days.

Table 6 is sourced from Table 8-5 of LADCO's 2021 Technical Support Document. This Table 6 updates Table 3 in Michigan's 2021 Regional Haze SIP submittal, which relied on modeling results using the 2011 base year, with the more recent modeling results using the 2016 base year.

Table 6: 2028_{2016} Tracer Contributions to b_{ext} on the Most Impaired Days at the LADCO Class I Areas

Source region tags	**Source contributions to 2028 visibility at IMPROVE Sites (Mm-1)**				**Percent source contributions to 2028 visibility at IMPROVE Sites (%)**			
IMPROVE Sites	**ISLE1**	**SENE1**	**BOWA1**	**VOYA2**	**ISLE1**	**SENE1**	**BOWA1**	**VOYA2**
Total Bext	**48.6**	**57.4**	**40.5**	**41.0**				
Rayleigh	12.0	12.0	11.0	12.0	24.7%	20.9%	27.2%	29.2%
Sea salt (SS)	0.3	0.2	0.2	0.3	0.5%	0.4%	0.5%	0.7%
Biogenic	1.4	1.8	1.2	1.3	2.9%	3.1%	2.9%	3.1%
ICBC	10.5	9.9	9.7	10.0	21.5%	17.2%	23.9%	24.4%
OC Estimated	4.2	5.1	3.6	3.5	8.6%	8.9%	8.9%	8.6%
Fire	0.9	0.9	0.9	0.4	1.9%	1.5%	2.1%	0.9%
Int'l anthropogenic	1.7	2.7	1.7	2.3	3.5%	4.8%	4.3%	5.7%
Offshore	0.2	0.2	0.1	0.1	0.5%	0.4%	0.1%	0.1%
West	1.6	1.9	1.9	1.8	3.4%	3.2%	4.6%	4.4%
Northeast	0.1	0.3	0.1	0.1	0.2%	0.5%	0.2%	0.2%
Southeast	0.4	1.3	0.2	0.2	0.8%	2.2%	0.6%	0.5%
CenSARA Other	2.4	1.8	1.9	1.5	4.9%	3.2%	4.6%	3.6%
IA	1.4	1.5	0.9	0.9	2.9%	2.6%	2.3%	2.1%
MO	1.4	1.7	0.8	0.6	3.0%	3.0%	2.1%	1.6%
TX	0.6	0.3	0.3	0.3	1.1%	0.6%	0.8%	0.7%
IL	2.0	3.6	0.6	0.4	4.0%	6.3%	1.6%	1.0%
WI	2.3	3.5	0.9	0.4	4.8%	6.2%	2.3%	1.0%
MI	1.7	3.4	0.1	0.2	3.5%	6.0%	0.3%	0.5%
OH	0.2	1.2	0.2	0.2	0.4%	2.0%	0.4%	0.5%
MN	2.4	1.7	3.9	4.4	5.0%	3.0%	9.6%	10.6%
IN (Total)	0.9	2.3	0.2	0.2	1.9%	4.0%	0.6%	0.5%
IN (Nonpoint)	0.3	0.7	0.1	0.1	0.6%	1.2%	0.2%	0.2%
IN (Rockport EGU)	0.0	0.1	0.0	0.0	0.1%	0.1%	0.0%	0.0%
IN (Gibson EGU)	0.0	0.1	0.0	0.0	0.1%	0.1%	0.0%	0.0%
IN (other EGU)	0.2	0.5	0.0	0.0	0.4%	0.8%	0.1%	0.1%
IN (Cement)	0.0	0.0	0.0	0.0	0.0%	0.1%	0.0%	0.0%
IN (Iron & Steel)	0.3	0.7	0.0	0.1	0.6%	1.2%	0.1%	0.1%
IN (Plastics & Resins)	0.0	0.0	0.0	0.0	0.0%	0.1%	0.0%	0.0%
IN (Aluminum)	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	0.0%
IN (Other Point)	0.1	0.2	0.0	0.0	0.2%	0.4%	0.1%	0.0%
Other Anthro	0.0	0.0	0.0	0.0	0.0%	0.0%	0.0%	0.0%
Aggregated by RPO								
Natural	2.3	2.7	2.0	1.6	5%	5%	5%	4%
LADCO	9.6	15.7	6.0	5.8	20%	27%	15%	14%
WRAP	1.6	1.9	1.9	1.8	3%	3%	5%	4%
CenSARA	5.8	5.4	4.0	3.3	12%	9%	10%	8%
VISTAS	0.4	1.3	0.2	0.2	1%	2%	1%	0%

Source: LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 – 2028 Planning Period: Technical Support Document," Table 8-5, June 17, 2021.

By sorting the regional visibility impairment contributions in units of inverse megameters (Mm^{-1}) in descending order for the source region tags in Table 6 above, 80 percent of the total contribution to visibility impairment at Isle Royale and 74 percent at Seney are attributed to regions with a contribution of 3.5 percent or greater.

Based on LADCO's 2028 modeled projections using the 2016 base year, Table 7 lists the Class I areas where Michigan contributes more than 1 percent to the 2028 modeled total light extinction. Although Michigan's contribution to visibility impairment is less than 1 percent at Voyageurs and Boundary Waters; both are listed below since they are located within the LADCO region.

Table 7: Class I Areas Impacted by Michigan Based on LADCO Source Apportionment Modeling Results for 2028, 2028 Adjusted Glidepath, and 2028 Projected Visibility on Most Impaired Days

Class I Area	State	LADCO 2028_{2016} Projected Total Light Extinction (Mm^{-1})	LADCO 2028_{2016} Projected Michigan Contribution (Mm^{-1})	LADCO 2028_{2016} Projected Michigan Contribution (%)
Seney Wilderness Area	MI	57.36	3.44	6.00%
Isle Royale National Park	MI	48.62	1.71	3.51%
Lye Brook Wilderness	VT	42.86	1.35	3.15%
Brigantine Wilderness Area	NJ	69.4	1.64	2.36%
Great Gulf Wilderness	NH	36.4	0.62	1.70%
Presidential Range-Dry River Wilderness	NH	36.4	0.62	1.70%
Mammoth Cave National Park	KY	74.18	1.11	1.49%
Acadia National Park	ME	41.9	0.59	1.42%
Shenandoah National Park	VA	50.63	0.66	1.29%
Swanquarter Wilderness Area	NC	48.52	0.62	1.29%
James River Face Wilderness	VA	53.42	0.62	1.15%
Moosehorn Wilderness Area	ME	37.33	0.41	1.09%
Roosevelt Campobello International Park	ME	37.33	0.41	1.09%
Dolly Sods Wilderness	WV	54.03	0.56	1.03%
Otter Creek Wilderness	WV	54.03	0.56	1.03%
Voyageurs National Park	MN	41.03	0.20	0.48%
Boundary Waters Canoe Area Wilderness	MN	40.51	0.11	0.28%

Source: LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 – 2028 Planning Period: Technical Support Document and Supplemental Materials," June 17, 2021 (*See* Appendices 2 and 3).

LADCO's "2021 Technical Support Document Modeling Files for the 2016 base year, 2028 modeling, specifically the "2016-based 2028 glidepaths and PSAT tracer contributions" spreadsheet posted on LADCO's electronic docket at https://www.ladco.org/reports/technical-support/ladco-regional-haze-tsd-second-implementation-period/

Based on the 2028 projections, Michigan is projected to contribute 3.44 Mm^{-1} to visibility impairment at Seney and 1.71 Mm^{-1} at Isle Royale, representing 6.00 percent and 3.51 percent to the total contributions to visibility impairment, respectively. To a lesser extent, Michigan is also projected to contribute 1.35 Mm^{-1} or less to visibility impairment at Class I areas in other states, representing 3.15 percent or less of the total contributions as shown in Table 7, above.

2.2. Addressing Impacts on Out-of-State Class I Areas

Under 40 CFR 51.308(f)(2)(ii)(B), States must consider and address the emissions reduction measures identified by other States for their sources as being necessary to make reasonable progress in the mandatory out-of-state Class I area.

Outside LADCO, the Mid-Atlantic/Northeast Visibility Union (MANE-VU) is the regional planning organization for the Northeastern and Mid-Atlantic States and Tribal Governments, which includes: Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Penobscot Indian Nation, Rhode Island, St. Regis Mohawk Tribe, and Vermont, and suburbs of Washington, D.C. Southeastern Air Pollution Control Agencies (SESARM) is the regional planning organization for Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia and the Eastern Band of the Cherokee Indians. Of the 17 Class I areas listed in Table 7, 4 are located in the LADCO states, 7 are located in the MANE-VU states, and 6 are located in SESARM. Michigan's contribution to visibility impairment in Class I areas is 6 percent or less in LADCO, 3.15 percent or less in MANE-VU, and 1.49 percent or less in SESARM.

As noted in Michigan's 2021 Regional Haze submittal, to the extent that Michigan affects Class I areas in other states, MANE–VU sent a letter to Michigan and other upwind states dated August 25, 2017, identifying large emission sources that MANE-VU wanted further controlled as a response to the Regional Haze Rule (*See* Appendix 4).

In Michigan, MANE-VU's August 25, 2017, letter identified the following units as contributing 3.0 Mm^{-1} or more to visibility impacts at one or more MANE-VU Class I areas based on 2011 and 2015 emissions:

- DTE – St. Clair Power Plant (Units 1, 2, 3, 4, 6, collectively)
- DTE – Belle River Power Plant (Units 1 and 2, separately)

For these sources, MANE-VU presented five requests:

- Ensure most effective use of control technologies on a year-round basis for EGUs > 25 MW.
- Perform four-factor analyses for new emission controls.
- Pursue an ultra-low sulfur fuel oil standard.
- Pursue enforceable means to lock in lower emission rates for sources >250 million British Thermal Units (MMBtu) / hour that have switched fuels.
- Consider energy efficiency, combined heat and power, as well as fuel cells, wind, and solar energy.

Additionally, on July 27, 2018, MANE-VU sent a consultation report to non-MANE-VU states that it identified as having sources that significantly contributed to visibility impairment at the Class I areas within the MANE-VU region (*See* Appendix 5). Michigan was determined to be one of the 14 states that MANE-VU identified for consultation. The July 27, 2018, MANE-VU requests included the following measures that would apply to sources in Michigan:

- A 90 percent reduction from the 2002 SO_2 emission levels should be achieved at the following uncontrolled sources in Michigan:

- DTE – Trenton Channel Power Plant, Unit 9A
- DTE – St. Clair, Unit 7

The State of New Jersey (a representative of MANE-VU) also approached Michigan with a request in a letter dated June 23, 2021: “Although New Jersey recognizes that St. Clair Power Plant is scheduled to be shut down in 2022 as stated in Section B of Michigan’s proposed SIP submittal, New Jersey requests that Michigan document in its SIP that this shutdown is permanent and enforceable.” (*See* Appendix E (*Comments Received*) of Michigan’s 2021 Second Planning Period Regional Haze Submittal to the USEPA.)

In response to the August 25, 2017, and July 27, 2018, MANE-VU requests, LADCO represented Michigan and the other LADCO states by replying with letters dated December 20, 2017, and May 23, 2018 (*See* Appendices 6 and 7). LADCO indicated that the 2011 and 2015 base year inventories and 2018 projections used by MANE-VU neglected the use of best available emissions information in the screening analysis, and that MANE-VU’s impact assessments did not accurately characterize the regional haze impacts of the LADCO sources on receptors in the MANE-VU region. LADCO explained that MANE-VU’s 2018 projections did not reflect significant shifts in the energy and industrial sections that had occurred.

As to the Michigan sources specifically identified by New Jersey and MANE-VU, EGLE responds that each was subject to a Federal Consent Decree in United States v. DTE Energy, Case No. 2:10-cv-13101-BAF-RSW (E.D. Mich.), which was entered May 14, 2020. https://www.justice.gov/enrd/consent-decree/file/1276421/download (*See* Appendix 8). The Consent Decree required DTE to “retrofit, refuel, or repower” the following units:

- Belle River Units 1 and 2 by December 31, 2030
- St. Clair Units 2, 3, 6 and 7 by December 31, 2022
- Trenton Channel Unit 9 by December 31, 2022

Each unit listed above has already taken measures to reduce emissions beyond the requests themselves. The emission reductions achieved are federally enforceable and permanent, and are discussed in further detail below in Section 3.3 for sources that already have Effective Emission Control Measures.

- St. Clair retired Unit 4 in 2017, Unit 1 in 2019, and Units 2, 3 ,6, and 7 in 2022, while Unit 5 has been retired since 1980. (*See* Appendix 33-A with the Certified Retired Unit Exemption Forms.)
- DTE – Trenton Channel, Unit 9A, retired in 2022. (*See* Appendix 33-C with the Certified Retired Unit Exemption Form.)

- DTE Belle River, Units 1 and 2, were required to operate a low NO_X combustion system with overfire air and became subject to emission limits of 0.290 lb./MMBtu NO_X, 0.680 lb./MMBtu SO_2, and 0.030 lb./MMBtu particulate matter (PM) under the Consent Decree. DTE is also in the process of converting Belle River Units 1 and 2 to natural gas by December 2025 and December 2026, respectively. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000008puPjAAI (*See* Appendix 9).

As discussed further below under Section 3.3.1, other large emitters of NO_X and SO_2 in the EGU category in Michigan have also experienced shutdowns and retirements since MANE-VU initiated consultation in 2017, such as the coal-fired boilers at the Consumers Energy – Dan E. Karn Plant, Lansing Board of Water and Light (LBWL) – Erickson Station, DTE Electric – River Rouge Power Plant, and Michigan Hub Plant. These shutdowns/retirements of coal-fired EGUs resulted in reduced emissions of greenhouse gases, as well as NOx and SO_2. Michigan expects that these operational changes will have a positive impact on visibility impairment at nearby Class I areas in surrounding states, including those that are part of MANE-VU.

3. Step 3: SELECTION OF SOURCES FOR ANALYSIS

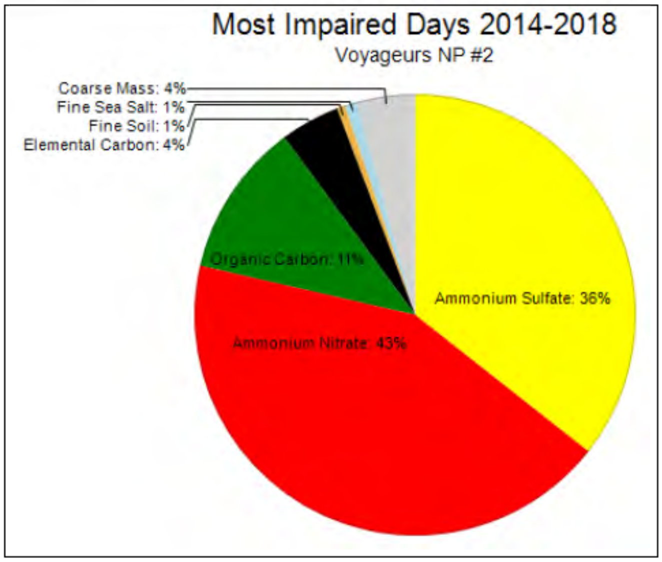
Select the emission sources for which an analysis of emission control measures will be completed in the second implementation period and explain the basis for these selections. For the purpose of this source selection step, a state may consider estimated visibility impacts (or surrogate metrics for visibility impacts), the four statutory factors, the five required factors listed in section 51.308(f)(2)(iv), and other factors that are reasonable to consider.

3.1 Determination of Which Pollutants to Consider

Contributing to regional haze are direct and precursor pollutants that primarily include SO_2, NO_X, fine and coarse PM, volatile organic compounds (VOC), and ammonia (NH_3). Depending on the location of the Class I areas, there may be only certain pollutants and precursors that dominate visibility impairment.

Based on the analyses in LADCO's 2021 Technical Support Document of the IMPROVE monitoring data, NO_X and SO_2 emissions were found to lead to the formation of the particulate species of nitrate and sulfate that currently contribute more to visibility impairment in the LADCO Class I Areas than $PM_{2.5}$, NH_3, and VOC. Figure 5 illustrates the PM species contribution plot for Voyageurs National Park, for which LADCO noted, "The PM species contributions for other LADCO region Class I areas are similar to Voyageurs." *See* LADCO's 2021 Technical Support Document, page 70.

Figure 5: Average PM Species Composition at Voyageurs National Park, Minnesota on the Most Impaired Days during 2014 – 2018



Source: LADCO's 2021 Technical Support Document, Figure 6-2.

The USEPA's August 20, 2019, "Guidance on Regional Haze State Implementation Plans for the Second Implementation Period" (2019 Regional Haze Guidance) states:

> "When selecting sources for analysis of control measures, a state may focus on the PM species that dominate visibility impairment at the Class I areas affected by emissions from the state and then select only sources with emissions of those dominant pollutants and their precursors." 2019 Regional Haze Guidance, page 11.

As discussed below in Section 3.2 Estimation of Baseline Visibility Impacts for Source Selection, EGLE's source selection process followed LADCO's approach in considering the sum of NH_3, NO_X, $PM_{2.5}$ and SO_2 emissions from Michigan sources divided by the distance to the closest Class I area. Then in Section 4 Characterization of Factors for Emission Control Measures, given the predominance of NO_X and SO_2 emissions contributing to visibility impairment at the LADCO Class I areas, EGLE focused on NO_X and SO_2 emissions in the evaluation of control measures necessary for reasonable progress.

3.2 Estimation of Baseline Visibility Impacts for Source Selection

To estimate visibility impacts for the purpose of selecting sources for further evaluation, the 2019 Regional Haze Guidance lists the following techniques from the least complicated to the most complicated and resource-intensive:

1) Emissions divided by distance (Q/d)
2) Trajectory analyses
3) Residence time analyses
4) Photochemical modeling (zero-out and/or source apportionment)

Among the least complicated techniques, a Q/d analysis is a surrogate analysis using tons/year emissions (Q) divided by distance in kilometers (d) from the Class I areas to estimate emissions source impacts at downwind receptors when air quality modeling would be overly resource-intensive and is not therefore a feasible process to support decision making.

3.2.1 Background on Previous Q/d Analysis

In an effort to support Region 5 states in the process of selecting sources/units for the Regional Haze Second Implementation Period, LADCO complied a detailed Q/d Analysis using the National Emissions Inventory (NEI) Collaborative 2016 alpha inventory for NO_X, SO_2, NH_3, VOCs, and fine particulate matter ($PM_{2.5}$) as the best available inventory at that time. *See* "Base Year Selection Workgroup Final Report," produced by the Inventory Collaborative Base Year Selection Workgroup, April 5, 2017. 2017-12-12_Base_Year_Selection_Report_V1.1.pdf

In Michigan's 2021 Regional Haze SIP submittal on pages 9-10, EGLE describes how Michigan's estimation relied on LADCO's Q/d method to identify sources in the state for a possible four-factor analysis. At the time, EGLE screened in sources using a Q/d > 4 based on 2016 actual emissions to represent approximately 80 percent of emissions from Michigan sources. Through this process, EGLE identified the following sources:

Paper Manufacturing Facilities:
- Neenah Paper
- Verso Quinnesec
- Verso Escanaba

Cement Manufacturer:
- St. Marys – Charlevoix

Lime Facility:
- Graymont – Gulliver

Power Plants:
- DTE – Monroe
- DTE – Belle River
- Consumers Energy – J.H. Campbell
- Consumers Energy – Dan E. Karn

During the FLM consultation process, the FLMs recommended Michigan also address the following facilities:

- Tilden Mining Company LC
- Holcim d/b/a Lafarge Alpena Plant
- LBWL – Erickson Station
- EES Coke Battery LLC
- Midland Cogeneration Venture
- L'Anse Warden Electric Company
- US Steel Great Lakes Works

3.2.2 Revised Q/d Analysis for the Selection of Impacting Sources

In this SIP supplement, EGLE re-examines LADCO's Q/d's analysis to further expand and refine its earlier source selection process.

Using the NEI collaborative 2016 alpha inventory to gather NO_X, SO_2, $PM_{2.5}$, VOCs, and NH_3 emissions data for an exhaustive list of Michigan sources of air pollution, LADCO's 2021 Technical Support Document provided calculations of the unit Q/d for each source. EGLE cross checked the inventory data with the Clean Air Markets Program Data (https://campd.epa.gov/) and the Michigan Air Emissions Reporting Systems Annual Pollutant Totals Query (https://www.egle.state.mi.us/maers/emissions_query.asp).

In selecting a Q/d threshold value that would serve as a metric for identifying sources of high impact potential on visibility impairment at Class I areas, EGLE's Air Quality Division (AQD) intended to set this threshold at a value that would capture nearly 80 percent of the total combined emissions of haze forming pollutants from all sources throughout the state.

The 2019 Regional Haze Guidance states, "In the most simple implementation of Q/d, metrics and thresholds can be defined on the basis of the sum of emissions of all visibility-impairing pollutants." The 2019 Regional Haze Guidance also notes, however, "it may be best to evaluate Q/d metrics on an individual pollutant basis. Additionally, since the magnitude of Q/d may vary considerably when total emissions are considered versus emissions of individual primary PM and precursor pollutants, appropriate pollutant-specific Q/d thresholds…may need to be considered." (2019 Regional Haze Rule, pg. 13.)

Table 8 lists each of the units indexed by LADCO's Q/d analysis with a Q/d of 1.0 or greater. Table 8 includes Q/d by unit level, facility level, and pollutant specific unit level (NO_X and SO_2). Unit level and facility level 'Q' were based on the sum of 2016 actual emissions for NH_3, NO_X, $PM_{2.5}$, and SO_2 in tpy. Pollutant-specific unit level Q was based on 2016 emissions for NO_X and SO_2, individually. The distance 'd' in kilometers (km) was from the source to the closest Class I area (CIA) drawn from the following list:

- Isle Royale National Park (ISLE)
- Seney Wilderness Area (SENE)
- Boundary Waters Canoe Area Wilderness
- Voyageurs National Park (VOYA)
- Mingo Wilderness Area
- Mammoth Cave National Park
- Dolly Sods Wilderness (DOSO)

The emissions for all analyzed sources were totaled and multiplied by a factor of 0.80 (80 percent). The target "80 percent" value functioned as a guidepost for setting a Q/d threshold to identify sources for possible four-factor analyses.

To capture 80 percent of emissions of NO_X and SO_2 collectively, an incremental evaluation led to a threshold Q/d>6 on an individual pollutant basis at the unit level for NO_X and SO_2 separately. As described in the 2019 Regional Haze Guidance, it may be best to evaluate Q/d metrics on an individual pollutant basis since the magnitude of a Q/d based on total emissions may vary considerably from a Q/d based on the individual primary PM and precursor pollutants. Inclusion of the other haze precursors ($PM_{2.5}$, VOC, and ammonia) in the Q/d analysis would not reflect NO_X and SO_2 as the dominant species contributing to visibility impairment in the LADCO Class I areas. Additionally, a unit pollutant level Q/d approach recognizes that the evaluation of control measures takes place at the unit level, and that addressing NO_X and SO_2 emissions would entail entirely different control systems. In the Q/d analysis below, a pollutant specific unit Q/d>6 threshold captured 70 percent of NO_X and 85 percent of SO_2 emissions, and 79 percent of both NO_X and SO_2, collectively.

In Table 8, units with a pollutant specific unit Q/d>6 are highlighted in green, and units that have retired or have an enforceable commitment to retire by 2028 or soon thereafter are highlighted in orange with an asterisk (*) to differentiate colors for viewing when no color option is available.

Table 8: Sources Listed by Q/d for Source Selection Process

KEY: Green shaded cells: Units selected based on Pollutant Specific Unit Q/d>6
Orange shaded cells with * to differentiate color: Units selected based on retirement

Facility Name	Sector	Agency Unit ID	Facility Unit ID	2016 Base Year Emissions (tpy) NH3	NOx	$PM_{2.5}$	SO_2	Total	Q/d Unit (sum)	Q/d NOx	Q/d SO_2	Q/d Facility (sum)	CIA (km)
TILDEN MINING COMPANY LC	NON-EGU	EU0087	EU Kiln 2–gas fired	0	5070	62.1	3.3	5135.3	42.8	42.3	0.0	108.6	ISLE
		EU0064	EU Kiln 1–gas fired	0	4544.5	143.4	4.1	4691.9	39.2	37.9	0.0		120
		EU0064	EU Kiln 1–coal fired	0	1545	48.7	131.2	1724.9	14.4	12.9	1.1		
		EU0087	EU Kiln 2 –coal fired	0	1320.5	16.2	105.5	1442.1	12	11.0	0.9		
ST. CLAIR / BELLE RIVER POWER PLANT	EGU	EU0120	Belle River Unit 2	0	3950.5	0.9	11590	15541.4	32.5	8.2	24.2	105.1	SENE
		EU0119	Belle River Unit 1	0	3040	0.2	9235	12275.2	25.6	6.3	19.3		479
*ST. CLAIR / BELLE RIVER POWER PLANT	EGU	EU0111	St. Clair Boiler 7	0	1046	2.6	5600	6648.6	13.9	*2.2	*11.7		
		EU0107	St. Clair Boiler 3	0	910	0	1780	2690	5.6	*1.9	*3.7		
		EU0106	St. Clair Boiler 2	0	913.5	0.4	1763	2676.9	5.6	*1.9	*3.7		
		EU0105	St. Clair Boiler 1	0	1273	0.3	2385.5	3658.8	7.6	*2.7	*5.0		
		EU0110	St. Clair Boiler 6	0	596	0.5	3019.5	3616	7.6	*1.2	*6.3		
		EU0108	St. Clair Boiler 4	0	694.5	0	1780.5	2475	5.2	*1.4	*3.7		
	NON-EGU	EU0117	St. Clair Diesel Generator 12-1	0	720.5	12.4	0.3	733.3	1.5	*1.5	*0.0		
*WISCONSIN ELECTRIC POWER COMPANY, Marquette – Presque Isle	EGU	EU0036	Boiler 9	0.1	926.5	0.6	1386.5	2313.7	20.4	*8.2	*12.3	84.9	ISLE 113
		EU0034	Boiler 7	0.1	934	0.6	1344.5	2279.2	20.1	*8.3	*11.9		
		EU0035	Boiler 8	0.1	895.5	0.6	1317.5	2213.7	19.5	*7.9	*11.7		
		EU0033	Boiler 6	0.1	503.5	0.4	921.5	1425.4	12.6	*4.5	*8.2		
		EU0032	Boiler 5	0.1	491.2	0.4	914.5	1406.1	12.4	*4.3	*8.1		
EMPIRE IRON MINING PARTNERSHIP	NON-EGU	EU0147	Unit 4	0	2021.5	33.5	271.9	2326.8	19.4	16.8	2.3	41.5	ISLE

Facility Name	Sector	Agency Unit ID	Facility Unit ID	2016 Base Year Emissions (tpy) NH3	NO_X	$PM_{2.5}$	SO_2	Total	Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)	CIA (km)
		EU0143	Unit 2	0	1350	97	50.6	1497.6	12.5	11.3	0.4		120
		EU0145	Unit 3	0	1010.5	96.5	50.4	1157.4	9.6	8.4	0.4		
*J. H. Campbell Plant	EGU	EU0062	Boiler 3	21.1	806.5	17.6	6900	7745.2	20.6	*2.1	*18.4	40.6	SENE
		EU0059	Boiler 1	6	1234.5	8.5	2522.5	3771.5	10	*3.3	*6.7		376
		EU0061	Boiler 2	9.8	305.2	21.7	3427	3763.7	10	*0.8	*9.1		
St. Marys Cement, Inc. - Charlevoix Plant	NON-EGU	RG0148	Compiled Kiln	6.8	2063	34	1178.5	3282.2	27.5	17.3	9.9	27.5	SENE 119
LAFARGE MIDWEST INC. - Alpena	NON-EGU	EU0181	Kiln 23	2.5	1419.5	4.5	452.8	1879.4	7.9	5.9	1.9	25.9	SENE
(Now Holcim (US), Inc.		EU0176	Kiln 22	2.7	1447.5	4.9	490	1945.1	8	6.0	2.0		240
DBA Lafarge Alpena Plant)		EU0161	Kiln 20	1.6	729.5	17.5	544.5	1293.1	5.4	3.0	2.3		
		EU0158	Kiln 19	1.5	630.5	10.3	445.4	1087.6	4.5	2.6	1.9		
*DTE - Electric Company TRENTON CHANNEL	EGU	EU0035	Boiler 9A	0	1763.5	12.1	9395	11170.6	24.2	*3.8	*20.3	25.8	DOS O
		RG0053	High Pressure Boilers	0	179.2	0.2	549.5	728.9	1.6	0.4	1.2		462
Verso Escanaba LLC (Now Billerud Escanaba LLC)	NON-EGU	EU0183	Recovery Furnace 10	0	623.5	107.8	15.2	746.5	7.2	3.1	0.1	22.5	ISLE
		EU0139	No. 11 Power Boiler	0	606.8	12.2	687.4	1306.4	12.7	3.0	3.4		201
		EU0161	Boiler 8	0	261.2	9.2	0.7	271.1	2.6	1.3	0.0		
NEENAH PAPER – MICHIGAN, INC - Munising	NON-EGU	EU0080	Boiler 1	0	264.6	1.4	588.5	854.5	15.5	4.8	10.7	15.5	SENE 55
Detroit Edison DTE Electric Company - Monroe Power Plant	EGU	EU0063	Unit 3	0	1220.5	7.5	800	2028	4.5	2.7	1.8	14.3	DOS O
		EU0064	Unit 4	0	1129.5	4.6	738.5	1872.6	4.1	2.5	1.6		454
		EU0062	Unit 1	0	998.5	4.6	529.5	1532.6	3.4	2.2	1.2		
		EU0068	Unit 2	0	760.5	5.7	275.3	1041.4	2.3	1.7	0.6		
Midland Cogeneration Venture	EGU	RG0063	SV0001	0.0	357.7	19.7	4.4	381.8	1.2	1.1	0.0	11.6	SENE 330
Combined Cycle Gas			SV0002	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		

Facility Name	Sector	Agency Unit ID	Facility Unit ID	2016 Base Year Emissions (tpy) NH3	NO_X	$PM_{2.5}$	SO_2	Total	Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)	CIA (km)
Turbines			SV0003	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0004	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0005	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0011	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0006	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0007	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0008	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0009	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
			SV0012	0.0	321.9	17.7	3.9	343.6	1.0	1.0	0.0		
*B. C. Cobb Plant	EGU	RG0028	Boilers 4 & 5	0.1	643.5	28.1	2712.5	3384.1	10	*1.9	*8.0	10	SENE 339
*DTE - Electric Company RIVER ROUGE	EGU	EU0040	Unit 3	0	1814	4.5	2723.8	4542.3	9.7	*3.9	*5.8	9.7	DOSO 470
*LBWL, Erickson Station	EGU	EU0007	Coal-fired boiler	0.1	1058.5	1.4	2588.5	3648.6	8.8	*2.6	*6.3	8.8	SENE 413
GRAYMONT WESTERN LIME, INC.	NON-EGU	EU0001	EU Kiln 1	0	254.5	13.3	19.6	287.4	8.1	7.1	0.5	8.1	SENE 36
TES Filer City Station	EGU	RG0017	Boilers 1 & 2	0.1	1373.5	46.4	360.1	1780.1	7.7	5.9	1.6	7.7	SENE 232
VERSO QUINNESEC LLC (Now Billerud Quinnesec LLC)	NON-EGU	EU0153	Recovery Furnace	0	603	73.9	14	691	4.2	3.7	0.1	7.6	SENE 164
		EU0159	Waste Fuel Boiler	9.1	418.8	13.2	117.9	558.9	3.4	2.6	0.7		
*LBWL - Eckert Station	EGU	RG0023	Coal Fired Boiler	0.1	785.5	12.4	1858	2656	6.4	*1.9	*4.5	6.4	SENE 412
*Consumers Energy – J.C. Weadock Facility	EGU	RG0060	Weadock 7 & 8	0	510.5	30.9	1635.5	2176.9	6.4	*1.5	*4.8	9.8	SENE 338
*Consumers Energy – D.E. Karn Facility		RG0058	Karn 1 & 2	0	213.8	12	283.9	509.7	3.4	*0.6	*0.8		SENE 338
L'ANSE WARDEN ELECTRIC COMPANY LLC	EGU	EU0009	Boiler 1	0.1	373.5	0.9	243.7	618.2	6.2	4.6	3.0	6.2	ISLE 82
*MARQUETTE BOARD OF LIGHT & POWER - Shiras	EGU	EU0003	Boiler 3	0	196.7	44.5	419	660.1	5.4	*1.7	*3.7	5.4	SENE 114

Facility Name	Sector	Agency Unit ID	Facility Unit ID	2016 Base Year Emissions (tpy)					Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)	CIA (km)
				NH3	NO_X	$PM_{2.5}$	SO_2	Total					
EES COKE BATTERY LLC	NON-EGU	EU0007	Coke Oven Gas Flare	0	521	200.9	1110	1831.9	1.4	1.1	2.4	5.3	DOSO 471
		EU0008	No. 5 Coke Battery	111.8	0	0	0	111.8	3.9	0.0	0.0		
PENINSULA COPPER INDUSTRIES, INC.	NON-EGU			86.5	0	0	0	86.5	3	0.0	0.0	5.3	ISLE
				0	202.9	21.1	503	727	2.3	5.3	13.2		38
J.R. WHITING CO.	EGU	EU0021	Boiler 3	0	217.4	18.8	484.7	720.9	1.6	0.5	1.1	4.6	DOSO
		EU0019	Boiler 1	0	178.3	6.1	440.6	625	1.6	0.4	1.0		453
		EU0020	Boiler 2	14.4	589	7.3	527.5	1138.2	1.4	1.3	1.2		
Marquette Branch Prison	NON-EGU	EU0005	Diesel Electric Generator	0	161.9	12.3	10.6	184.7	1.6	1.4	0.1	3.3	SENE 113
		EU0006	Diesel Electric Generator	0	161.9	12.3	10.6	184.7	1.6	1.4	0.1		
Guardian Industries, LLC	NON-EGU	EU0079	Line 1	0	917	271.5	343.9	1532.4	3.3	2.0	0.7	3.3	DOSO 470
GREAT LAKES GAS TRANSMISSION STATION #10	OIL GAS	EU0006	Unit 1001	0	61.3	2.6	1.4	65.3	1.5	1.4	0.0	2.7	SENE 44
		EU0007	Unit 1002	0	49.1	2.1	1.1	52.2	1.2	1.1	0.0		
Morton Salt, Inc.	NON-EGU	EU0023	Boiler	0	161.3	15	393.9	570.2	2.5	0.7	1.7	2.5	SENE 230
J.B. Sims Generating Station	EGU	EU0023	PC Boiler	0	459.4	9.5	364.9	833.8	2.3	1.3	1.0	2.3	SENE 359
CARMEUSE LIME, INC., RIVER ROUGE OPERATION	NON-EGU	RG0025	Kilns 1 & 2	0	565	6.2	438.2	1009.4	2.1	1.2	0.9	2.1	DOSO 471
WEYERHAEUSER NR COMPANY	NON-EGU	RG0062	Dryers 1, 2, 3, 4 and Coen Burner	0	94.2	339.7	3.1	437	2.1	0.4	0.0	2.1	SENE 213
Consumers Energy - Muskegon River Compressor Station	OIL GAS	RG0062	Engines H9, H10, H11, H12 (HBA-10) and T11, T12	0	508.7	7.8	0.1	516.5	2	2.0	0.0	2	SENE 257

Facility Name	Sector	Agency Unit ID	Facility Unit ID	2016 Base Year Emissions (tpy) NH3	NOx	$PM_{2.5}$	SO_2	Total	Q/d Unit (sum)	Q/d NOx	Q/d SO_2	Q/d Facility (sum)	CIA (km)
ANR Pipeline Company - Lincoln Compressor Station	OIL GAS	EU0017	Natural Gas Compressor Engine	0	497.8	8.4	0.1	506.3	1.8	1.8	0.0	1.8	SENE 274
Cadillac Renewable Energy Facility	EGU	EU0006	Wood/bark Boiler	9	177.7	17.1	57.7	261.3	1.1	0.8	0.3	1.1	SENE 229
Packaging Corporation of America - Filer City Mill	NON-EGU	EU0037	Boiler 1	2.8	246.7	6.7	0.5	256.7	1.1	1.1	0.0	1.1	SENE 232
Great Lakes Gas - Farwell Compressor Station 12	OIL GAS	EU0016	Natural Gas Engine	0	279.9	8.5	0.1	288.5	1.1	1.0	0.0	1.1	SENE 274
Viking Energy of McBain	EGU	EU0003	Wood Fired Boiler	0	37.8	2.2	206.7	246.7	1	0.2	0.9	1	SENE 239
DETROIT RENEWABLE POWER LLC	EGU	EU0020	Boiler 11	0	435.4	3	45.6	484	1	0.9	0.1	1	DOS O 475
TOTAL EMISSIONS for Sources with Unit Q/d of 1.0 or Greater				287	68,547	2,259	91,160	162,252					
TOTAL Emissions from Sources with Unit Q/d > 6 per Pollutant + Retirements					48,273		77,413						
% of Total Emissions Represented by Selected Sources					**70%**		**85%**						

Source:

- LADCO's "Modeling and Analysis for Demonstrating Reasonable Progress for the Regional Haze Rule 2018 – 2028 Planning Period: Technical Support Document," June 17, 2021. *See* Appendices G and H.
- LADCO's 2021 Technical Support Document Modeling Files for the 2016 base year, 2028 modeling, specifically the "Process level report of Q/D sources (Haze_Control_Sheet_6.9.xlsx)" spreadsheet posted on LADCO's electronic docket at https://www.ladco.org/reports/technical-support/ladco-regional-haze-tsd-second-implementation-period/
- Clean Air Markets Program Data https://campd.epa.gov/
- Michigan Air Emissions Reporting Systems Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

To summarize, the application of the pollutant specific unit Q/d>6 threshold as a screening tool for the Q/d data compiled by LADCO generated the following updated list of 'selected sources' for possible four-factor analyses. Although the FLMs recommended selecting EES Coke Battery LLC, Midland Cogeneration Venture, L'Anse Warden Electric Company, and US Steel Great Lakes Works, emissions for these sources were below the pollutant specific unit Q/d>6 threshold and beyond EGLE's 80 percent target. As shown in Table 9 below, the pollutant specific unit Q/d>6 threshold level captured Michigan's largest sources with the greatest impacts on visibility impairment.

Table 9: Sources Selected for Possible Four-factor Analysis

KEY: Green shaded cells: Units selected based on Pollutant Specific Unit Q/d>6
Orange shaded cells with * to differentiate colors: Units selected based on Retirement

Facility Name	Sector	Facility Unit ID	Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)
TILDEN MINING COMPANY LC	NON-EGU	EU Kiln 2–gas fired	42.8	42.3	0.0	108.6
		EU Kiln 1–gas fired	39.2	37.9	0.0	
		EU Kiln 1–coal fired	14.4	12.9	1.1	
		EU Kiln 2 –coal fired	12	11.0	0.9	
ST. CLAIR / BELLE RIVER POWER PLANT	EGU	Belle River Unit 2	32.5	8.2	24.2	105.1
		Belle River Unit 1	25.6	6.3	19.3	
*ST. CLAIR / BELLE RIVER POWER PLANT	EGU	St. Clair Boiler 7	13.9	*2.2	*11.7	
		St. Clair Boiler 3	5.6	*1.9	*3.7	
		St. Clair Boiler 2	5.6	*1.9	*3.7	
		St. Clair Boiler 1	7.6	*2.7	*5.0	
		St. Clair Boiler 6	7.6	*1.2	*6.3	
		St. Clair Boiler 4	5.2	*1.4	*3.7	
	NON-EGU	St. Clair Diesel Generator 12-1	1.5	*1.5	*0.0	
*WISCONSIN ELECTRIC POWER COMPANY, Marquette – Presque Isle	EGU	Boiler 9	20.4	*8.2	*12.3	84.9
		Boiler 7	20.1	*8.3	*11.9	
		Boiler 8	19.5	*7.9	*11.7	
		Boiler 6	12.6	*4.5	*8.2	
		Boiler 5	12.4	*4.3	*8.1	
EMPIRE IRON MINING PARTNERSHIP	NON-EGU	Unit 4	19.4	16.8	2.3	41.5
		Unit 2	12.5	11.3	0.4	
		Unit 3	9.6	8.4	0.4	
*J. H. Campbell Plant	EGU	Boiler 3	20.6	*2.1	*18.4	40.6
		Boiler 1	10	*3.3	*6.7	
		Boiler 2	10	*0.8	*9.1	
St. Marys Cement, Inc. - Charlevoix Plant	NON-EGU	Compiled Kiln	27.5	17.3	9.9	27.5
LAFARGE MIDWEST INC. – Alpena (Now Holcim (US), Inc. DBA Lafarge Alpena Plant	NON-EGU	Kiln 23	7.9	5.9	1.9	25.9
		Kiln 22	8	6.0	2.0	
*DTE - Electric Company TRENTON CHANNEL	EGU	Boiler 9A	24.2	*3.8	*20.3	25.8

Facility Name	Sector	Facility Unit ID	Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)
Verso Escanaba LLC (Now Billerud Escanaba LLC)	NON-EGU	Recovery Furnace 10	7.2	3.1	0.1	22.5
		No. 11 Power Boiler	12.7	3.0	3.4	
NEENAH PAPER – MICHIGAN, INC. - Munising	NON-EGU	Boiler 1	15.5	4.8	10.7	15.5
*B. C. Cobb Plant	EGU	Boilers 4 & 5	10	*1.9	*8.0	10
*DTE - Electric Company RIVER ROUGE	EGU	Unit 3	9.7	*3.9	*5.8	9.7
*LBWL, Erickson Station	EGU	Coal-fired boiler	8.8	*2.6	*6.3	8.8
GRAYMONT WESTERN LIME, INC.	NON-EGU	EU Kiln 1	8.1	7.1	0.5	8.1
*LBWL - Eckert Station	EGU	Coal Fired Boiler	6.4	1.9	4.5	6.4
*Consumers Energy – J.C. Weadock Facility	EGU	Weadock 7 & 8	6.4	*1.5	*4.8	9.8
*Consumers Energy – D.E. Karn Facility		Karn 1 & 2	3.4	*0.6	*0.8	
*MARQUETTE BOARD OF LIGHT & POWER – Shiras	EGU	Boiler 3	5.4	*1.7	*3.7	5.4

3.3 Sources that already have Effective Emission Control Measures

The 2019 Regional Haze Guidance explains that it may be reasonable for a state not to select sources for a four-factor analysis if those sources already have effective emission controls in place. (*See* 2019 Regional Haze Guidance, pg. 22.)

3.3.1 Sources with Retirements

As explained in the 2019 Regional Haze Guidance, under 40 CFR 51.308(f)(1)(iv)(C), states may consider source retirement and replacement schedules in not selecting sources for a four-factor analysis if they have an enforceable commitment to retire by 2028 or soon thereafter. Within the 2021 Clarifications Memorandum, the USEPA articulates that “anticipated source shutdowns could be considered the most stringent on-the-way measure and may be relied upon to forgo a four-factor analysis or shorten the remaining useful life of a source.” (*See* 2021 Clarifications Memo, pg. 10.)

Michigan’s 2021 Regional Haze SIP submittal discussed plans for upcoming retirements at facilities that were selected for evaluation. Of the sources selected for a possible four-factor analysis under Section 3.2.2 above, this SIP supplement provides confirmation of those sources that have retired as well as those having an enforceable commitment to retire by 2028.

EGLE selected for evaluation the retirements of coal and fossil fuel-fired electrical generation at 30 EGUs at 12 different power plants during the second implementation period. Based on the 2016 emissions inventory, retirements that have already occurred during the second implementation period between 2018 and 2024 account for 17,417 tpy NO_X and 42,655 tpy SO_2. Three additional coal-fired EGUs are required to retire under a settlement agreement by May 31, 2025. These retirements represent additional reductions in emissions of 2,346 tpy NO_X and 12,850 tpy SO_2 based on the 2016 inventory. Together, these reductions represent a historically significant decrease in Michigan’s statewide emissions by 30 percent for NO_X and 65 percent for SO_2 from all units in the second implementation period with a sum Q/d of 1.0 or greater.

Two additional coal-fired EGUs will be retired under the same settlement agreement by May 31, 2031, representing additional reductions of 40 tpy of NO_X and 58 tpy of SO_2 in the third implementation period.

Table 10 lists the permanent shutdowns/retirements of 44 units from 18 different Michigan power plants, which occurred during 2016 – 2024. Retirements that occurred during 2016 and 2017 before the beginning of the second implementation period are also included in Table 10 below for completeness given that LADCO's Q/d source selection process and 2028 projection modeling were based on units that were operating in 2016. Other retirements that have occurred since 2016 for sources that were not included in LADCO's Q/d list have also been included in Table 10 below.

The shutdowns/retirements of these units are considered permanent and enforceable. Under EGLE's regulations, when a unit is no longer permitted to operate, the unit cannot resume operation without being considered a "new" unit subject to New Source Review and Prevention of Significant Deterioration (PSD).

USEPA Retired Unit Exemption Forms have been included in the appendices for each unit. (*See* Appendix 33.) With each Retired Unit Exemption Form filed with the USEPA, the owner/operator certifies the date the unit was or will be retired and that the unit shall not emit any NO_X or SO_2 from that date forward.

Although not all the units listed in Table 10 were selected during EGLE's revised source selection process mentioned previously, EGLE is adopting the retirements that occurred during the second implementation period between 2018 to 2024 into the LTS since the retirements are already federally enforceable and permanent.

Table 10: Retirements of Michigan EGUs from 2016 – 2024

Facility Name	Sector	Facility Unit ID	Retirement Date	2016 Emissions (tpy)			
				NH3	NO_X	$PM_{2.5}$	SO_2
ST. CLAIR / BELLE RIVER POWER PLANT	EGU	St. Clair Boiler 7	5/31/2022	0	1046	2.6	5600
		St. Clair Boiler 3	5/31/2022	0	910	0	1780
		St. Clair Boiler 2	5/31/2022	0	913.5	0.4	1763
		St. Clair Boiler 1	3/27/2019	0	1273	0.3	2385.5
		St. Clair Boiler 6	5/31/2022	0	596	0.5	3019.5
		St. Clair Boiler 4	11/13/2017	0	694.5	0	1780.5
WISCONSIN ELECTRIC POWER COMPANY, Marquette – Presque Isle	EGU	Boiler 9	4/8/2019	0.1	926.5	0.6	1386.5
		Boiler 7	4/8/2019	0.1	934	0.6	1344.5
		Boiler 8	4/8/2019	0.1	895.5	0.6	1317.5
		Boiler 6	4/8/2019	0.1	503.5	0.4	921.5
		Boiler 5	4/8/2019	0.1	491.2	0.4	914.5
DTE - Electric Company TRENTON CHANNEL	EGU	Boiler 9A	7/8/2022	0	1763.5	12.1	9395
		Unit 16	4/16/2016				
		Unit 17	4/16/2016				
		Unit 18	4/16/2016		86.2		263
		Unit 19	4/16/2016		286.8		94
B. C. Cobb Plant	EGU	Boiler 4	4/15/2016	0.1	643.5	28.1	2712.5
		Boiler 5	4/15/2016		215.6		1449.6
DTE - Electric Company RIVER ROUGE	EGU	Unit 1	6/7/2021	0	1814	4.5	2723.8
		Unit 2	4/16/2016		0	0	0

Facility Name	Sector	Facility Unit ID	Retirement Date	2016 Emissions (tpy) NH3	NOx	$PM_{2.5}$	SO_2
		Unit 3	6/1/2021		1859.4	3.6	2805.7
LBWL, Erickson Station	EGU	Unit 1	11/28/2022	0.1	1058.5	1.4	2588.5
LBWL, Eckert Station	EGU	Unit 1	12/31/2020	0.1	785.5	12.4	1858
		Unit 3	12/31/2020				
		Unit 4	5/31/2021				
		Unit 5	12/31/2020				
		Unit 6	12/31/2020				
Consumers Energy – J.C. Weadock Facility	EGU	Weadock 7	4/15/2016	0	510.5	30.9	1635.5
		Weadock 8	4/15/2016				
Consumers Energy – D.E. Karn Facility		Karn 1	6/1/2023	0	213.8	12	283.9
		Karn 2	6/1/2023				
MARQUETTE BOARD OF LIGHT & POWER - Shiras	EGU	Boiler 3	4/29/2019	0	196.7	44.5	419
Michigan Hub Plant	EGU	Unit 1	9/30/2017		132.9	0.8	139.5
DTE – Pontiac North LLC		EUBHB9	1/10/2017	0	0	0	0
Graphic Packing International, Inc. - Kalamazoo		Unit BLR08	10/07/2024		82.1	4.5	0.4
J B Sims		Unit 3	6/1/2020	0	459.4	9.5	364.9
J R Whiting		Unit 1	4/15/2016	0	217.4	18.8	484.7
		Unit 2	4/15/2016	0	178.3	6.1	440.6
		Unit 3	4/15/2016	14.4	589	7.3	527.5
James De Young		Unit 5	6/1/2017		0.1	0	0
Consumers Energy - Thetford		Unit 2	6/1/2019		0		0.6
		Unit 3	4/1/2018		0		0.8
		Unit 4	6/1/2019		0		1.5
Wyandotte		Unit 8	6/30/2016		0	0	0.0

In addition to the retirements that have already occurred, the following units will be retired in the future, although not all were selected for a possible four-factor analysis under Section 3.2.2.

- **Consumers Energy – J.H. Campbell Plant: Units 1, 2, and 3**

  Units 1, 2, and 3 are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 14, 20, and 21 (*See* Appendix 1). This SIP supplement provides further elaboration.

  Consumers Energy – J.H. Campbell Power Plant is subject to a settlement agreement approved by the Michigan Public Service Commission on April 20, 2020, which requires closure/retirement of coal-fired Units 1, 2, and 3 on or before May 31, 2025. *See* April 20, 2022, Settlement Agreement – Michigan Public Service Commission, Case No. U-21090 – In the Matter of the Application of Consumers Energy Company for Approval of and Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000002gLkGAAU (*See* Appendix 10).

  The settlement agreement was executed by Consumers Energy Company, the Michigan Public Service Commission staff, Michigan Environmental Council, the Natural Resources Defense Council, the Sierra Club, Attorney General Dana Nessel, Environmental Law and Policy Center, Vote Solar, Ecology Center, Union of Concerned

Scientists, Urban Core Collective, Citizens Utility Board of Michigan, Hemlock Semiconductor Operations LLC, Michigan Energy Innovation Business Council, Institute for Energy Innovation, Clean Grid Alliance, Michigan Electric Transmission Company LLC, and Great Lakes Renewable Energy Association.

The settlement agreement was affirmed in the State of Michigan Court of Appeals. *See* No. 362294 Public Service Commission, LC No. 00-021090, March 23, 2023. https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000007I2GEAA0 (*See* Appendix 11).

When retired sometime before May 31, 2025, the permanent shutdown of coal-fired Units 1, 2 and 3 at Consumers Energy – J.H. Campbell Power Plant will represent a reduction in emissions of 2,346 tpy NO_X and 12,850 tpy SO_2 based on the 2016 inventory.

- **Consumers Energy – Dan E. Karn, Units 3 and 4**

Units 3 and 4 are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 14,15, 21, and 22 (*See* Appendix 1). This SIP supplement provides further elaboration.

Consumers Energy – Dan E. Karn Power Plant is subject to the same settlement agreement mentioned above for the J.H. Campbell Plant that was approved by the Michigan Public Service Commission on April 20, 2022. The settlement agreement requires closure/retirement of coal-fired Units 3 and 4 at Consumers Energy – Dan E. Karn on or before May 31, 2031. *See* April 20, 2022, Settlement Agreement - Michigan Public Service Commission, Case No. U-21090 (*See* Appendix 10). In 2023, Consumers Energy voluntarily converted Units 3 and 4 from coal to natural gas and fuel oil – approximately 8 years ahead of its 2031 retirement deadline. https://www.consumersenergy.com/news-releases/news-release-details/2023/06/14/15/30/consumers-energy-takes-next-step-to-clean-energy-future-by-closing-karn-coal-plants.

Although 2031 is beyond the end of the second implementation period in 2028, the 2019 Regional Haze Guidance states, "if a source is certain to close by December 31, 2028 (or soon thereafter), under an enforceable requirement, a state can reasonably consider that to be sufficient reason to remove the source from further analysis and reasonable progress consideration" (2019 Regional Haze Guidance, pg. 42).

Although Units 3 and 4 did not appear on LADCO's list in Table 8 because the Q/d for both units was below 1.0, the emission reductions are still noteworthy. When retired sometime before May 31, 2031, the permanent shutdown of coal-fired Units 3 and 4 at Consumers Energy – Dan E. Karn will represent a reduction in emissions of 40 tpy NO_X and 58 tpy SO_2 based on the 2016 inventory.

3.3.2 Source that is Indefinitely Idled

- **Cleveland-Cliffs, Inc. – Empire Iron Mining Partnership**

  Empire Iron Mining Partnership was among the sources screened in using EGLE's revised Q/d analysis based on emissions from a 2016 base year; however, since 2016, the facility has been idled indefinitely. A recent January 17, 2024, on-site inspection report by EGLE's AQD documented the following conditions:

  > "Production at the facility ceased on August 3, 2016, and the mine was indefinitely idled after the last stockpile of finished pellets were shipped. While there are currently no plans in place to begin production, the facility is being preserved in a care and maintenance mode to preserve its ability to restart when market conditions and pellet pricing support access of remaining ore reserves. The facility would need to undergo significant maintenance to restart production, and a large wastewater treatment plant would need to be constructed in order to treat the water currently in the pit."
  >
  > "Empire is considered a major source and is required to report its annual emissions through the Michigan Air Emissions Reporting System (MAERS). However, the facility has been idled since 2016, so no emissions have been reported since then." *See* EGLE's AQD Activity Report: On-Site Inspection, January 17, 2024. https://www.egle.state.mi.us/aps/downloads/SRN/B1827/B1827_SAR_20240117.pdf (*See* Appendix 12).

  Given the uncertainty of future operations and the significant maintenance and construction that would need to take place to restart production, EGLE did not select this source for an analysis of control measures for the second implementation period. If the facility resumes operations, EGLE will revisit and revise its determination not to select this source for an analysis of control measures.

3.3.3 Sources with Existing Effective Control Measures

The USEPA provided clarification for sources with existing effective control measures in a memorandum entitled, "Clarifications Regarding Regional Haze State Implementation Plans for the Second implementation Period," July 8, 2021 (2021 Clarifications Memo).[3] The USEPA stated that "a source that otherwise would undergo four-factor analysis (e.g., because it exceeds a threshold of emissions divided by distance or Q/d, visibility, or other source-selection threshold) may forgo a full four-factor analysis if it is already 'effectively controlled.'" (*See* 2021 Clarifications Memo, pg. 5.) The 2019 Regional Haze Guidance provided examples to illustrate scenarios in which the USEPA believes it may be reasonable for a state not to select a particular source that is effectively controlled for further analysis. (*See* 2019 Regional Haze Guidance, pages 22-25.)

The USEPA noted in the 2021 Clarifications Memo that after a state first assesses whether a source operates an 'effective control,' a "source's existing measures are generally needed to prevent future visibility impairment; i.e., to prevent future emission increases, and thus

[3] https://www.epa.gov/system/files/documents/2021-07/clarifications-regarding-regional-haze-state-implementation-plans-for-the-second-implementation-period.pdf

necessary to make reasonable progress. Measures that are necessary to make reasonable progress must be included in the SIP. However, there may be circumstances in which a source's existing measures are not necessary to make reasonable progress." (*See* 2021 Clarifications Memo, pg. 9.) To support such a determination, the USEPA described a weight-of-evidence demonstration based on the source's most recent 5-year historical emission rate, projected emissions and emission rate, and enforceable limits related to its existing measures to demonstrate that "the source has consistently implemented its existing measures and has achieved, using those measures, a reasonably consistent emission rate." (*See* 2021 Clarifications Memo, pg. 9.)

EGLE determined that the following sources, identified through EGLE's source selection process in Table 9 above, are effectively controlled, thereby forgoing a full four-factor analysis. Additionally, EGLE demonstrates below that the effectively controlled measures are not necessary to include in the regulatory portion of the SIP to prevent future emission increases and to make reasonable progress during the second implementation period consistent with the 2021 Clarifications Memo in Section 4.1.

To assist in making the determinations, EGLE supplemented LADCO's Q/d analysis and 2028 modeled projections with data from the Michigan Air Emissions Reporting Systems Annual Pollutant Totals Query (https://www.egle.state.mi.us/maers/emissions_query.asp), Clean Air Markets Program Data (Clean Air Markets Program Data (CAMPD) | US EPA), and the USEPA's 2022v1 Emissions Modeling Platform (https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform). The USEPA's 2022v1 Emissions Modeling Platform is based on the most recent 2020 National Emissions Inventory, which was released in the spring of 2023, and provides updated emissions data for 2022, as well as modeling of emissions data on a facility-wide basis for future years of 2026, 2032, and 2038.

Table 11: Units with Existing Effective Control Measures

Facility Name	Sector	Facility Unit ID	Q/d NOX	Q/d SO_2
TILDEN MINING COMPANY LC	NON-EGU	EU Kiln 1–gas fired	37.9	
		EU Kiln 1–coal fired	12.9	
ST. CLAIR / BELLE RIVER POWER PLANT	EGU	Belle River Unit 2	8.2	24.2
		Belle River Unit 1	6.3	19.3
St. Marys Cement, Inc. - Charlevoix Plant	NON-EGU	Compiled Kiln	17.3	9.9
LAFARGE MIDWEST INC. – Alpena (Now Holcim (US), Inc. DBA Lafarge Alpena Plant	NON-EGU	Kiln 23	5.9	
		Kiln 22	6.0	
NEENAH PAPER – MICHIGAN, INC. - Munising	NON-EGU	Boiler 1		10.7

3.3.3.1 TILDEN MINING COMPANY LC

- Kiln 1:
  Q/d NO_X 37.9 – Natural gas-fired
  Q/d NO_X 12.9 – Coal-fired
  Q/d NO_X 50.8 – Overall

Tilden Mining Company LC, Kiln 1 is described in detail in Michigan's 2021 Regional Haze SIP submittal on pages 12 and 19.

Nearly three years after Michigan submitted its 2021 Regional Haze SIP, on April 23, 2024, the USEPA published a proposed settlement agreement in Cleveland-Cliffs, Inc. v. Environmental Protection Agency, Case No. 16-2643, which was published in the Federal Register (89 FR 30360). https://www.govinfo.gov/content/pkg/FR-2024-04-23/pdf/2024-08612.pdf (*See* Appendices 13 and 14).

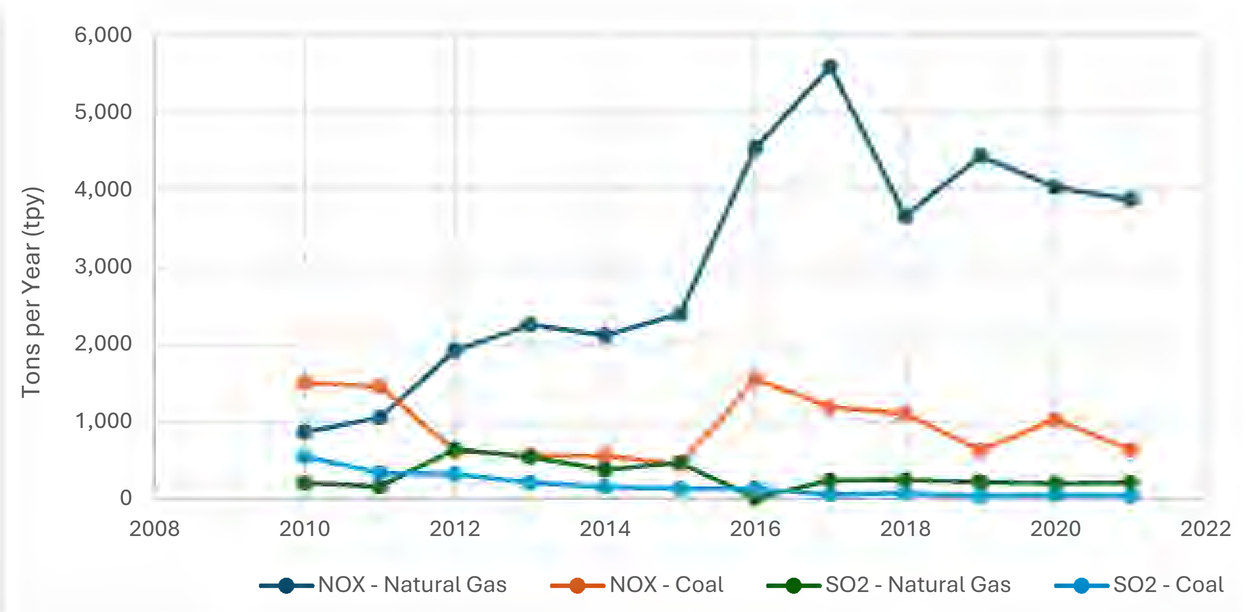
If finalized, the proposed settlement agreement would set forth revised NO_X Best Available Retrofit Technology (BART) limits for Kiln 1 in a Federal Implementation Plan (FIP) that would be incorporated into Tilden's Renewable Operating Permit (ROP) at the state level. On December 4, 2024, the USEPA proposed a revision to the Taconite FIP for Michigan and Minnesota, which includes NO_X and/or SO_2 limits for Kiln 1 based on the conditions within the proposed settlement agreement detailed in the paragraph above.

Despite ongoing litigation surrounding the NO_X/SO_2 BART limits established in the 2015 FIP Rule, Tilden's ROP has been modified to add a condition specifying that the facility must comply with the applicable requirements of 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart X—Michigan, Section 52.1183 Visibility Protection, which would include the newly proposed BART limits for Kiln 1 beginning 30 days after the date of publication in the Federal Register. EGLE would then re-open the ROP and incorporate the FIP BART limits into the ROP in accordance with the renewal schedule.

Given the current situation, it would be illogical for the AQD to pursue further NO_X control measures while previously litigated federal requirements are in the process of being settled at the federal level. When the revised FIP is finalized, the revised limits for Kiln 1 will be federally enforceable, the ROP will incorporate the FIP BART limits, and Kiln 1 will be considered effectively controlled. Until the FIP is finalized, EGLE cannot yet include the revised FIP in Michigan's LTS.

Figure 6 and Table 12 illustrate the annual emissions from Kiln 1 as fired by natural gas and coal from 2010 to 2021.

Figure 6: Tilden Mining Company LC, Kiln 1 - Annual Emissions (in tons) as fired by Natural Gas and Coal (2010 – 2021)



Source: MAERS Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

Table 12: Tilden Mining Company LC, Kiln 1: Annual Emissions (in tons) as fired by Natural Gas and Coal (2010 – 2021)

Year	NOX - Natural Gas	NOX - Coal	SO_2 - Natural Gas	SO_2 - Coal
2010	862	1,498	203	543
2011	1,046	1,453	155	331
2012	1,919	617	639	316
2013	2,250	558	537	205
2014	2,116	551	373	150
2015	2,391	440	462	131
2016	4,545	1,545	4	131
2017	5,595	1,186	237	50
2018	3,663	1,097	240	72
2019	4,438	626	216	31
2020	4,033	1,025	195	50
2021	3,870	631	205	34

Source: MAERS Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

3.3.3.2 DTE – ST. CLAIR/BELLE RIVER POWER PLANT

- Belle River Unit 1, Q/d NO_X: 6.3; Q/d SO_2: 19.3
- Belle River Unit 2, Q/d NO_X: 8.2; Q/d SO_2: 24.2

DTE – St. Clair/Belle River Power Plant, Belle River Units 1 and 2, are discussed in detail in Michigan's 2021 Regional Haze SIP submittal on pages 13 and 20. This SIP supplement provides further elaboration.

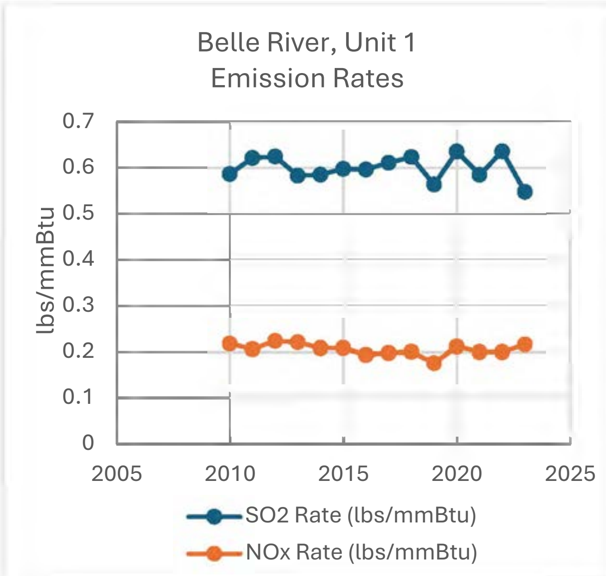
DTE – Belle River, Units 1 and 2 are subject to a federal Consent Decree. *See* United States v. DTE Energy, Case No. 2:10-cv-13101-BAF-RSW (E.D. Mich)., Consent Decree filed May 14, 2020. (*See* Appendix 8, https://www.justice.gov/enrd/consent-decree/file/1276421/download.) The Consent Decree requires DTE to "retrofit, refuel, or repower" Belle River Units 1 and 2 by December 31, 2030. According to news outlets, DTE – Belle River Units 1 and 2 will be converted to natural gas ahead of schedule by December 2025 and December 2026, respectively. (*See* Appendix 9: 12-14-2022 Power Engineering Article: https://www.power-eng.com/coal/dte-energy-officially-retires-two-coal-plants/#gref.) (*See* also Appendix 16: 9-5-2024 WPHM News Article, https://www.wphm.net/2024/09/05/belle-river-gas-conversion-begins-next-year/#:~:text=The%20%24154%20million%20investment%20is,a%20tour%20of%20the%20plant.")

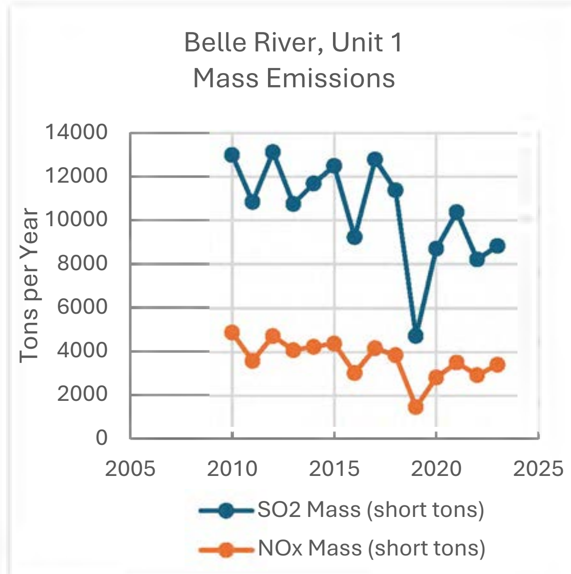
Although the Consent Decree does not require Belle River Units 1 and 2 to retrofit, refuel or repower until December 31, 2030, two years beyond the end of the second implementation period in 2028, the 2019 Regional Haze Guidance notes, "The year 2028 is not a bright line for these considerations, so a state may be able to justify not selecting a source for analysis of control measures because there is an enforceable requirement for the source to cease operation by a date after 2028." (*See* 2019 Regional Haze Guidance, pg. 20.) Although not fully ceasing operation by 2028, in this case, Belle River Units 1 and 2 have an enforceable requirement to cease operation with the use of coal by 2030.

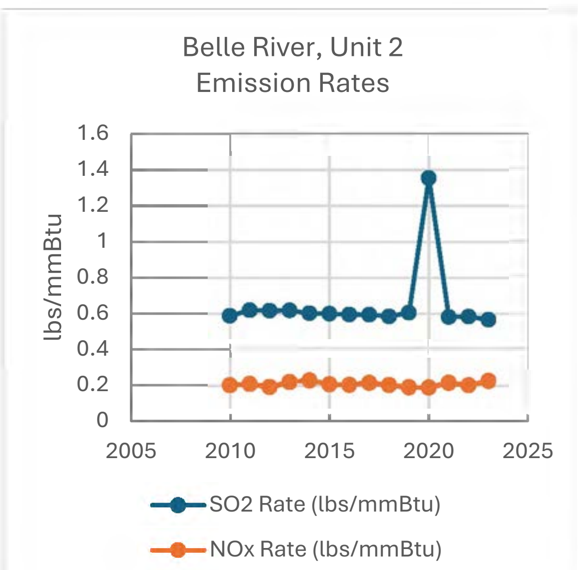
Since Belle River Units 1 and 2 are considered effectively controlled under the Federal Consent Decree and the Consent Decree is already federally enforceable, EGLE is including it in Michigan's LTS for the second implementation period.

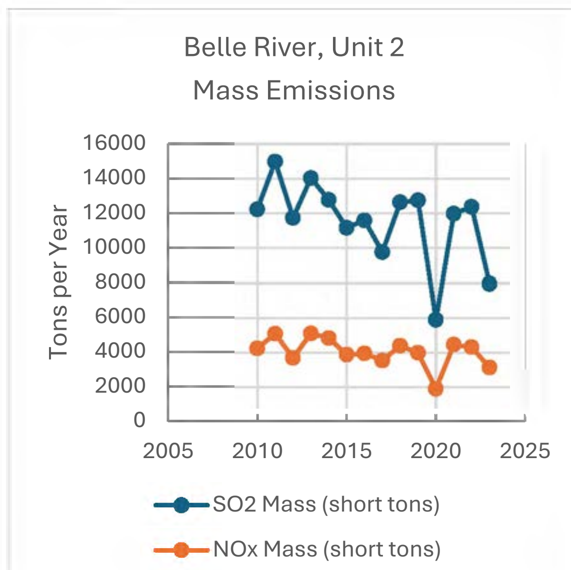
Figure 7 and Table 13 depict the SO_2 and NO_X annual emission rates and mass emissions from 2010 – 2023 for Belle River Unit 1 and Unit 2. With the retrofitting, refueling, or repowering under the Consent Decree, emission rates are expected to decrease dramatically, preventing future emission increases and future visibility impairment, leading to reasonable progress.

Figure 7: DTE – St. Clair/Belle River Power Plant: Belle River Units 1 and 2: Emission Rates and Mass Emissions (2010 – 2023)









Source: Clean Air Markets Program Data
https://campd.epa.gov/

Table 13: DTE – St. Clair/Belle River Power Plant, Belle River Units 1 and 2: Emission Rates and Mass Emissions (2010 – 2023)

Unit	Year	SO_2 (lb./MMBtu)	NO_X (lb./MMBtu)	SO_2 (tpy)	NO_X (tpy)
1	2010	0.587	0.218	12992.33	4888.729
	2011	0.6218	0.2063	10844.55	3594.419
	2012	0.6248	0.2239	13127.13	4730.661
	2013	0.5834	0.2209	10752.03	4086.574
	2014	0.5857	0.2088	11691.05	4239.782
	2015	0.5982	0.2091	12495.72	4385.617
	2016	0.5968	0.1938	9235.916	3043.498
	2017	0.6114	0.1981	12793.03	4169.662
	2018	0.6238	0.2007	11384.78	3857.1
	2019	0.5644	0.1768	4739.351	1480.958
	2020	0.6359	0.212	8704.394	2835.029
	2021	0.5853	0.2003	10377.34	3516.849
	2022	0.6361	0.2002	8212.738	2940.672
	2023	0.5483	0.2161	8831.158	3418.006
2	2010	0.5885	0.2029	12229.09	4245.376
	2011	0.6202	0.21	14987.74	5092.765
	2012	0.6171	0.1934	11741.21	3694.442
	2013	0.6194	0.2206	14034.35	5111.914
	2014	0.6026	0.2301	12775.47	4841.232
	2015	0.6002	0.2087	11166.33	3878.082
	2016	0.5962	0.2052	11591.58	3954.595
	2017	0.5951	0.2167	9765.679	3544.41
	2018	0.5854	0.2038	12637.73	4395.036
	2019	0.6063	0.1915	12753.45	3988.847
	2020	1.3551	0.1904	5892.147	1911.493
	2021	0.5823	0.2166	11973.83	4459.964
	2022	0.5846	0.203	12375.95	4313.716
	2023	0.5671	0.2269	7961.242	3142.187

Source: Clean Air Markets Program Data
https://campd.epa.gov/

3.3.3.3 St. Marys Cement, Inc. – Charlevoix Plant

- Compiled Kiln, Q/d NO_X: 17.3; Q/d SO_2: 9.9

St. Marys Cement, Inc. – Charlevoix Plant, Kiln 1 is described in detail in Michigan's 2021 Regional Haze SIP submittal on pages 13, 19, and 20.

NO_X:
In 2012, the USEPA promulgated a FIP for St. Marys Cement, Inc. – Charlevoix Plant. *See* Proposed Rule 77 FR 46912 (8/6/2012), (https://www.govinfo.gov/content/pkg/FR-2012-08-

06/pdf/2012-19039.pdf) and Final Rule 77 FR 71533 (12/3/2012) (https://www.govinfo.gov/content/pkg/FR-2012-12-03/pdf/2012-29014.pdf). Under the FIP, the USEPA provided a BART analysis that required installation of selective non-catalytic reduction (SNCR) system for NO_X.

The Compiled Kiln at St. Marys Cement, Inc. – Charlevoix Plant currently operates an SNCR (post-combustion control), in combination with an indirect fire system, which includes low NO_X burners (LNB), at an average reduction efficiency of 50 percent to meet the two NO_X limits (2.80 lb. per ton of clinker [30-day rolling-average] and 2.40 lb. per ton of clinker [12-month rolling average]) established in the USEPA's 2012 BART FIP for Michigan (per 40 CFR 52.1183(h)). (*See* 77 Federal Register 71533, December 3, 2012.)

Given the federally enforceable requirements under the FIP, EGLE found it was not necessary to evaluate and/or pursue additional NO_X control devices, since the kiln is equipped with both precombustion (LNB) and post-combustion (SNCR) abatement technologies. It would be technically infeasible and cost ineffective to retrofit the kiln with additional pre- or post-combustion controls.

Although coal and petroleum coke are the primary fuels for the kiln, the kiln is designed to use asphalt flakes, plastic, and small quantities of cellulose fiber as alternative fuels. Currently, plastics are the only type of alternative fuel being utilized by the unit. The facility has determined that the use of asphalt flakes as a fuel source for the kiln would negatively impact product quality.

SO_2:
SO_2 emissions for the kiln are limited to 1,175 pounds per hour and 7.5 pounds per ton of clinker produced (per 40 CFR 52.1183(h)). In the USEPA's 2012 BART FIP for Michigan, the USEPA determined that the installation and operation of SO_2 controls is not warranted under "current circumstances" but would be necessary if higher sulfur feed materials were used. Similarly, the USEPA found that removal of SO_2 at normal emission rates for this unit would result in a cost-per-ton value of $4,500 or greater. *See* 77 FR 71533, December 3, 2012, https://www.govinfo.gov/content/pkg/FR-2012-12-03/pdf/2012-29014.pdf .

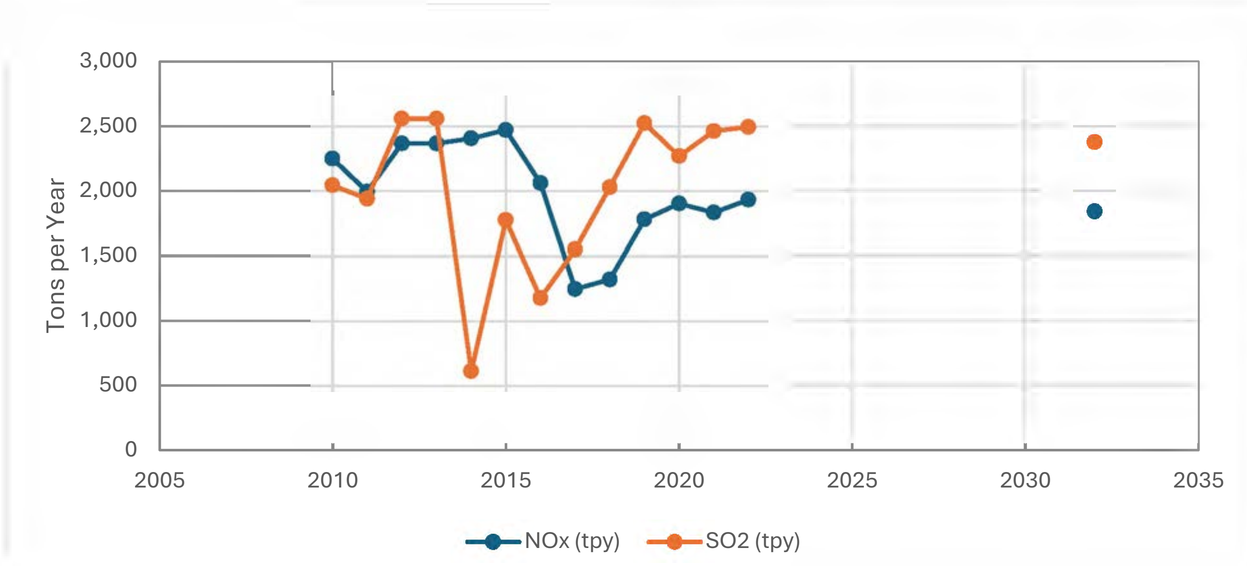
EGLE found that it was not necessary to evaluate and/or pursue SO_2 control devices since the estimated cost-per-ton of SO_2 removal is greater than the cost-effectiveness thresholds (noted in the USEPA's currently implemented rules above) to determine whether a control measure is economically reasonable. Moreover, the facility is not planning to use higher sulfur feed materials that were evaluated by the USEPA under the 2012 BART FIP. Although coal and petroleum coke are the primary fuels for the kiln, the kiln is designed to use asphalt flakes, plastic, and small quantities of cellulose fiber as alternative fuels. Currently, plastics are the only type of alternative fuel being utilized by the unit. The facility has determined that the use of asphalt flakes as a fuel source for the kiln would negatively impact product quality.

Emission Trends:
Table 14 and Figure 8 illustrate the trends in facility-wide actual NO_X and SO_2 emissions for 2010 – 2022 and 2032. The USEPA's 2022v1 Emissions Modeling Platform[4] projects both facility-wide NO_X and SO_2 emissions to be lower for St. Marys Cement – Charlevoix in 2032 than what was reported in 2022. With the BART FIP limits and the 10-year future projections indicating that both NO_X and SO_2 emissions will be reduced source-wide, St. Marys Cement – Charlevoix is projected to continue to implement the existing measures for the kiln and not to

[4] https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

increase its emission rate. As such, EGLE has concluded that the in-line kiln system is "effectively controlled" for both NO_X and SO_2 emissions for the second implementation period, and that the existing control measures are not necessary for reasonable progress to prevent future emission increases and future visibility impairment.

Figure 8: St. Marys Cement, Inc. – Charlevoix Plant: Annual Actual and Projected Emissions (2010 – 2032)



Source: MAERS Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform (https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform)

Table 14: St. Marys Cement, Inc. – Charlevoix Plant: Annual Actual and Projected Emissions (2010 – 2032)

Year	NO_X (tpy)	SO_2 (tpy)
2010	2,251	2,045
2011	1,996	1,942
2012	2,369	2,560
2013	2,369	2,560
2014	2,408	614
2015	2,473	1,777
2016	2,063	1,179
2017	1,248	1,551
2018	1,322	2,031
2019	1,782	2,525
2020	1,904	2,271
2021	1,835	2,464
2022	1,934	2,496
2032 (Projected)	1,844	2,380

Source: MAERS Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform (https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform)

3.3.3.4 Holcim (US), Inc. DBA Lafarge Alpena Plant (Formerly Lafarge Midwest, Inc. – Alpena)

- Kiln 22: Q/d NO_X: 6.0
- Kiln 23: Q/d NO_X: 5.9

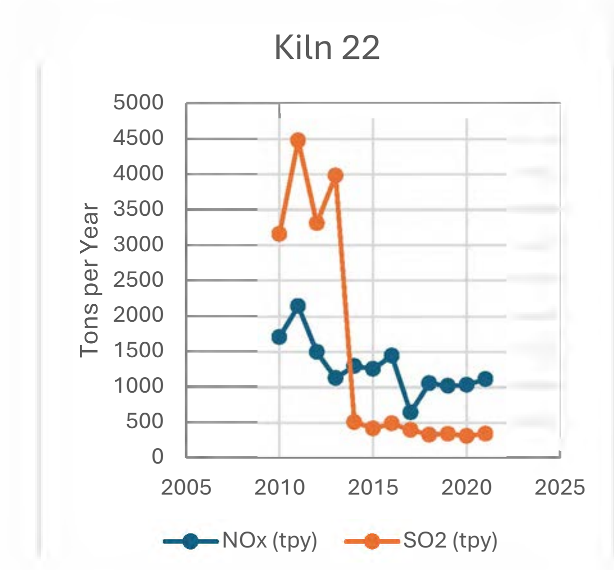
In 2010, Lafarge Midwest became subject to a Federal Consent Decree that required NO_X and SO_2 controls as well as limits on a facility-wide tons per year limit and 12-month rolling SO_X and NO_X limits at the Alpena Plant. *See* Consent Decree between Lafarge Midwest, Inc., the United States, the State of Michigan and other states and jurisdictions (USA, USEPA, Michigan, et al. v. Lafarge; U.S. District Court Civil Action No. 3:10-cv-00044-JPG-CJP) entered March 18, 2010. A copy of the Consent Decree is available at: https://www.epa.gov/sites/default/files/documents/lafarge-cd.pdf (*See* Appendix 17).

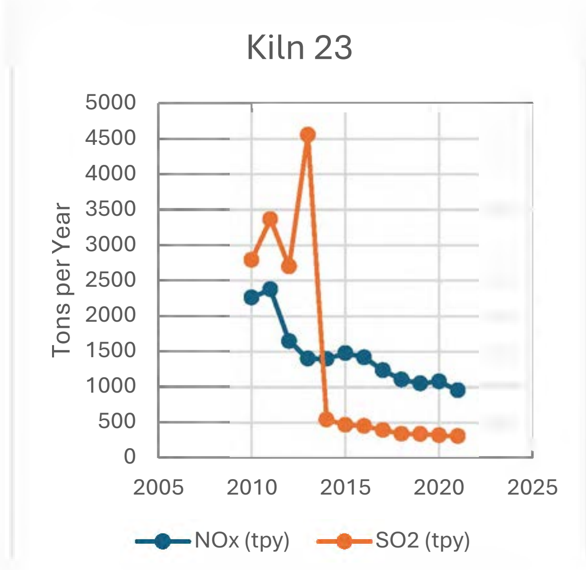
In 2012, Lafarge Midwest was also subject to a BART analysis, which accepted the Consent Decree requirements as BART. *See* 77 FR 46912 (August 6, 2012). https://www.govinfo.gov/content/pkg/FR-2012-08-06/pdf/2012-19039.pdf.

As described in greater detail in Section 8.3.1 below regarding the Status of Control Strategies, Lafarge installed SNCR NO_X controls on each kiln, along with dry absorbent addition (DAA) for SO_2 control on Kilns 19, 20, 21, and wet flue gas desulfurization (FGD) SO_2 control on Kilns 22 and 23. The limits and other requirements of the Consent Decree and the selected SO_2 and NO_X control systems were incorporated in Permit to Install (PTI) No. 195-10B, issued on September 13, 2013 (*See* Appendix 18).

Based on the requirements and limits set in the federal Consent Decree, the BART analysis, and installation of SNCR controls, as well as an examination of the facility limits, declining historic emission rate trends and projected emissions, EGLE has concluded that Kiln 22 and Kiln 23 are effectively controlled and that the existing measures are not necessary for reasonable progress for the second implementation period to prevent future emission increases and future visibility impairment.

Figure 9: Holcim (US), Inc. DBA Lafarge Alpena Plant, Kiln 22 and Kiln 23: Annual Emission Rates (2010 – 2021)





Source: MAERS Annual Pollutant Total Query https://www.egle.state.mi.us/maers/emissions_query.asp

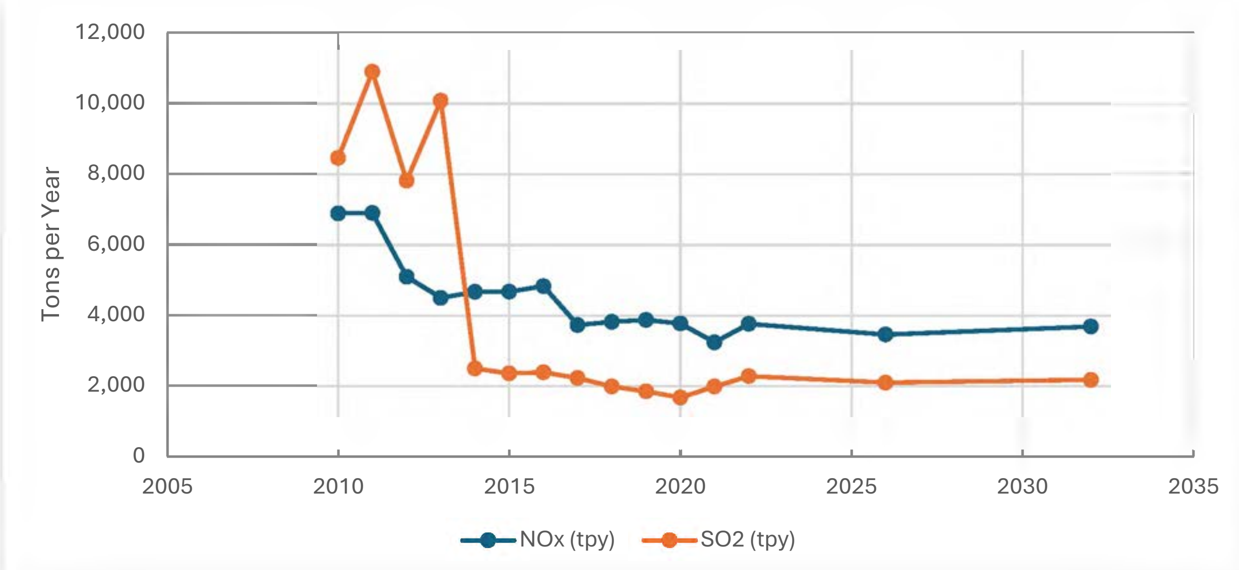
Table 15: Holcim (US), Inc. DBA Lafarge Alpena Plant, Kiln 22 and Kiln 23: Annual Emission Rates (2010 – 2021)

Lafarge Kiln 22		
Year	NO_X (tpy)	SO_2 (tpy)
2010	1710	3156
2011	2147	4479
2012	1499	3310
2013	1132	3983
2014	1301	510
2015	1259	418
2016	1448	490
2017	646	398
2018	1056	331
2019	1021	342
2020	1035	313
2021	1116	345

Lafarge Kiln 23		
Year	NO_X (tpy)	SO_2 (tpy)
2010	2262	2794
2011	2379	3367
2012	1650	2701
2013	1403	4555
2014	1398	543
2015	1480	469
2016	1419	453
2017	1239	396
2018	1106	343
2019	1053	339
2020	1081	321
2021	956	311

Source: MAERS Annual Pollutant Total Query https://www.egle.state.mi.us/maers/emissions_query.asp

Figure 10: Holcim (US), Inc. DBA Lafarge Alpena Plant: Facility-wide Actual and Projected Emissions (2010 – 2032)



Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

Table 16: Holcim (US), Inc. DBA Lafarge Alpena Plant: Facility-wide Actual and Projected Emissions (2010 – 2032)

Year	NO_X (tpy)	SO_2 (tpy)
2010	6,894	8,466
2011	6,907	10,905
2012	5,102	7,820
2013	4,504	10,087
2014	4,673	2,504
2015	4,677	2,364
2016	4,834	2,397
2017	3,734	2,232
2018	3,825	1,994
2019	3,880	1,858
2020	3,778	1,681
2021	3,246	1,994
2022	3,767	2,287
2026	3,466	2,104
2032	3,692	2,180

Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

3.3.3.5 Neenah Paper – Michigan, Inc. – Munising

- Boiler 1, Q/d SO_2: 10.7

Neenah Paper – Michigan, Inc. Boiler 1 is described in detail in Michigan's 2021 Region Haze SIP on pages 10, 15, and16. (*See* Appendix 1.)

EGLE examined Boiler 1 from two different angles by providing a demonstration of existing effective controls and by considering the potential exclusion of nearby sources from selection for the sake of reference.

Demonstration of Existing Effective Controls:
Boiler 1 is capable of burning bituminous coal or natural gas. As shown in Table 17 below, SO_2 emissions result primarily from the burning of the bituminous coal compared to natural gas. SO_2 emissions are restricted by the ROP for Neenah Paper (MI-ROP-B1470-2013), which requires that the coal burned in Boiler 1 (Emission Unit ID EU05) shall not exceed a maximum sulfur content of 1.5 percent by weight calculated on the basis of 12,000 BTUs per pound of coal. This condition is federally enforceable and was established pursuant to Michigan Rule 201(1)(a).

In its ROP, Neenah Paper – Michigan, Inc. is also subject to the CAA Section 112 National Emission Standards for Hazardous Air Pollutants (NESHAP) since the facility is a source of HAP emissions. In May 2015, a spray dry absorber (SDA) was installed on Boiler 1 to reduce facility-wide hazardous air pollutants (HAP) to less than major source thresholds, in time to reclassify the facility as a minor HAP source to comply with the federal Boiler Generally Available Control Technologies (GACT) regulations before the effective date within the GACT regulation. Neenah Paper – Michigan, Inc. requested limits be placed on its HAP potential to emit for the entire mill to levels below the applicable major source thresholds, i.e., less than 10 tpy for a single HAP and less than 25 tpy for all HAPs combined. With the HAP emission limits in place, Boiler 1 has operated as an area source of HAPS since February 2016 and is subject to 40 CFR Part 63, Subpart JJJJJJ, NESHAP: Industrial, Commercial and Institutional Boilers.

The SDA on Boiler 1 is used to reduce HAPs, mainly hydrogen chloride (HCl) acid gas; however, the SDA also provides collateral removal of SO_2. In June 2016, Neenah Paper – Michigan, Inc. submitted a PTI Application to make enhancements to the SDA to improve the operation of the system and the control efficiency. (*See* https://www.egle.state.mi.us/aps/downloads/srn/B1470/B1470_RVN_20170825.pdf.) The permit application stated that SDA performance to date had "proven effective for both HCl and SO_2 removal," but the SDA scrubber modifications would further improve reliability. The enhancements were expected to be complete and ready for stack testing by January 31, 2017, and the permit application noted, "The SDA will effectively reduce SO_2 emissions…" The permit application referenced the restriction in the ROP limiting the sulfur content of the coal and noted, "The SO_2 requirement in Rule 201 also applies to Boiler 1; the use of SDA control technology will enhance Boiler 1's ability to comply with this Rule. Furthermore, the current sulfur content of the coal used in Boiler 1 is less than 1%."

After the SDA system was installed and later enhanced in 2017, SO_2 emissions from Boiler 1 decreased sharply as Neenah Paper – Michigan, Inc. improved the operation and efficiency of the SDA system to better control HAPs, took limits on its HAP potential to emit, and used more natural gas instead of coal. As shown in Table 17 and Figure 11 below, SO_2 emissions from Boiler 1 decreased from 810 tpy in 2010 to 270 tpy in 2021, with a sharp, sustained decrease occurring in 2019, after the SDA enhancements, to half the level it was in 2016.

Neenah Paper – Michigan, Inc.'s strategy to reduce HAP emissions to meet the NESHAPs has also resulted in reduced SO_2 emissions. Calculating a revised Q/d using more recent SO_2 emissions for Boiler 1 from 2019 to 2021, rather than 2016 as used in the LADCO analysis, results in a pollutant specific unit Q/d of 4.9 or less, which would rank it below Michigan's Q/d threshold of 6. With the existing measures resulting in consistent annual SO_2 emissions over the past 5 years of 270 tpy or less, an evaluation would likely result in the conclusion that there is a low likelihood that additional controls would provide further reductions.

The 2019 Regional Haze Guidance provides that, "If a source owner has recently made a significant expenditure that has resulted in significant reductions of visibility impairing pollutants at an emissions unit, it may be reasonable for the state to assume that additional controls for that unit are unlikely to be reasonable for the upcoming implementation period." (*See* 2019 Regional Haze Guidance, pages 22 and 23). As such, the investment by Neenah Paper – Michigan, Inc. in installing the SDA system in 2015 and making enhancements in 2017 to improve the operation of the system and control efficiency, for both HAPs and SO_2, constitutes a significant recent expenditure that has resulted in effective reductions of SO_2 from Boiler 1, such that additional controls are unlikely to provide further reductions.

Based on the Boiler 1's existing measures and enforceable requirements described above, as well as the most recent 5 years of emission rate data available provided below in Figures 11 and 12 and Table 17 and 18, Neenah Paper – Michigan, Inc. is projected to continue to implement the existing measures for Boiler 1 and not to increase its emission rate through 2032. As such, EGLE has determined that the existing measures are not necessary to include in the LTS or the regulatory portion of the SIP to prevent future emission increases and future visibility impairment.

Consideration for Excluding Nearby Sources from Selection
Boiler 1 was selected for further analysis based on its pollutant specific unit Q/d of 10.7 for SO_2, which was calculated using the 2016 emissions of 588 tons and a 55-km distance to the nearest Class I area: Seney Wilderness Area. The relatively high Q/d compared to other Michigan sources is a result of being located closer to a Class I area. Other Michigan sources with a pollutant specific unit Q/d less than that of Neenah Paper – Michigan Inc.'s Boiler 1 include large power plants because of the nature of their locations farther away from a Class I area. For example, St. Clair Boiler 6 was ranked with a Q/d of 6.3 using the 2016 SO_2 emissions of 3,020 tons, an amount 5 times greater than the 2016 SO_2 emissions from Neenah Paper's Boiler 1, because it is located much farther away – 479 km from the nearest Class I area. Similarly, Presque Isle Boiler 6 emitted 922 tons SO_2 in 2016, nearly 2 times more than Neenah Paper's Boiler 1, resulting in a lower pollutant specific unit Q/d of 8.2 based on its location 113 km from the nearest Class I area.

For the sake of reference, a Q/d screening method for establishing a threshold for excluding nearby sources from source selection has been used to evaluate NAAQS under the USEPA's rules for PSD. (*See* "EPA Nearby Source Selection Guidance," Minnesota Pollution Control Agency, November 2023, https://gaftp.epa.gov/aqmg/SCRAM/conferences/2023_13th_Conference_On_Air_Quality_Modeling/Presentations/1-18_Nearby%20Source%20Selection%20Guidance%20Whitepaper%20MPCA.pdf.)

For the short-term NAAQS, such as the 24-hour NAAQS, the USEPA described an approach for an applicant of a PSD permit to determine the impact of various sources.

> "In determining which emission sources in the screening area should be added to the emissions inventory, the applicant should consider three criteria: (1) annual emissions of the source, (2) degree of ambient impact, and (3) distance from the impact area. For example, a 100-ton-per-year source located 10 kilometers from the impact area generally can be excluded from the inventory because its effect on air quality in the impact area is expected to be insignificant. However, a 10,000-ton-per-year source located 40 kilometers from the impact areas would probably have to be accounted for in the increment analysis." (*See* USEPA's "Prevention of Significant Deterioration Workshop Manual," 450280081. Office of Air, Noise, and Radiation, Office of Air Quality Planning and Standards (Research Triangle Park, NC, 1980): page I-C-18, https://www.epa.gov/sites/default/files/2015-07/documents/1980wman.pdf.)

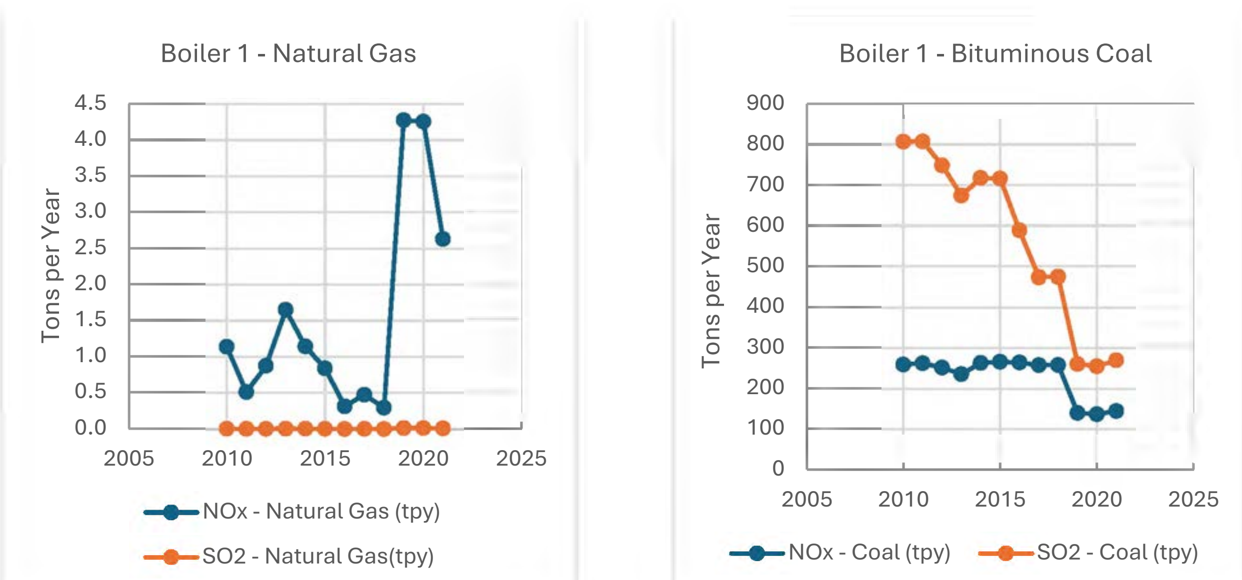
Based on this screening technique, the State of North Carolina's PSD permitting program developed a "20D" threshold, which received USEPA concurrence. For the short-term NAAQS, North Carolina's 20D approach excludes nearby sources that have potential allowable emissions 'Q' in tpy that are less than 20 times the distance 'd' between the nearby source and the source under review. (*See* Eldewins Haynes, Meteorologist, Air Permits Unit, State of North Carolina Department of Natural Resources and Community Development, to Lewis Nagler, Air Management Branch, USEPA Region IV, Atlanta, Georgia, July 22, 1985, A screening method for PSD.)

Although intended for NAAQS and PSD purposes, the 20D approach gives a sense of the magnitude of influence for the sake of nearby source selection for determining impacts at Class I areas. In the case of Neenah Paper – Michigan, Inc., Boiler 1 would be evaluated based on its potential to emit and its distance from the nearest Class I area: Seney Wilderness Area.

The potential of Boiler 1 to emit SO_2 is derived from its 202 MMBtu/hr capacity and its ROP permit limitation on sulfur content of 1.5 percent by weight calculated on the basis of 12,000 BTU/lb coal, resulting in a potential to emit of 1,105 tpy SO_2. The distance to Seney Wilderness Area is 55 km, and 20 times the distance of 55 km would be 1,100 km. Using the 20D approach, this places the potential to emit of 1,105 tpy SO_2 nearly equivalent to the 20D value of 1,100 km, which would be used to exclude this source from consideration in an air quality modeling demonstration for PSD.

Overall Determination:
Based on the recent significant investment in the SDA by Neenah Paper – Michigan, Inc. that has resulted in effective reductions of SO_2, the sulfur and HAP limitations in the ROP permit, Boiler 1's declining SO_2 emission rates over the past 5 years, and the facility's declining projected emissions for SO_2 through 2032, EGLE has concluded that Boiler 1 is effectively controlled and that the existing measures are not necessary for reasonable progress for the second implementation period to prevent future emission increases and future visibility impairment.

Figure 11: Neenah Paper – Michigan, Inc., Boiler 1: Annual Emissions from Natural Gas and Coal (2010 – 2021)



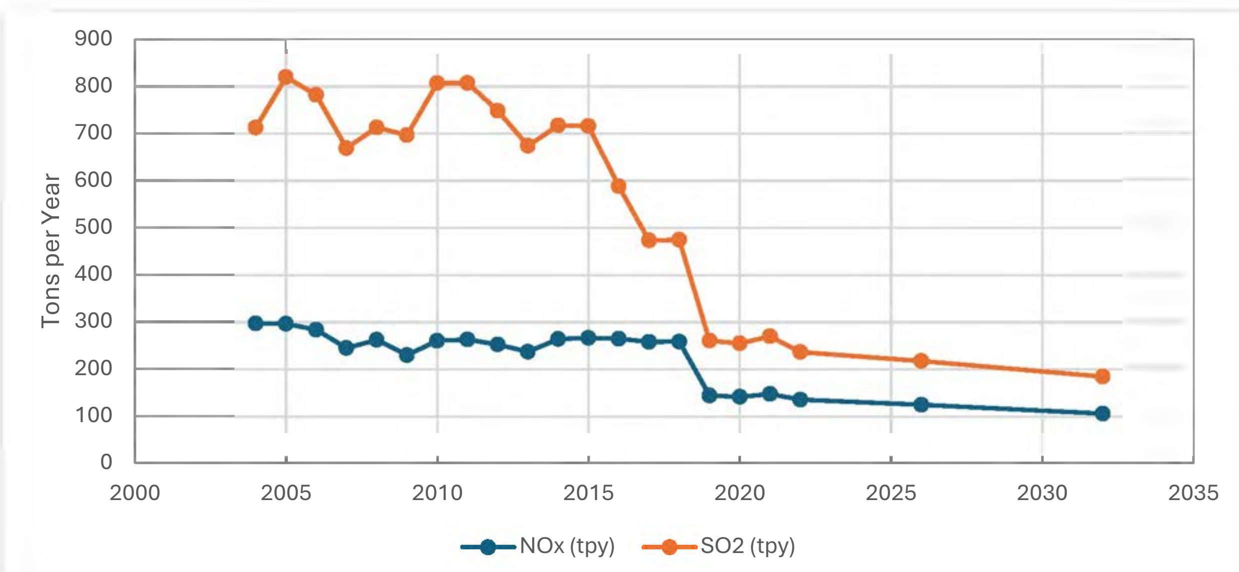
Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 17: Neenah Paper – Michigan, Inc., Boiler 1: Annual Emissions from Natural Gas and Coal (2010 – 2021)

Year	NO_X - Natural Gas (tpy)	SO_2 - Natural Gas (tpy)	NO_X - Coal (tpy)	SO_2 - Coal (tpy)
2010	1.1	0.0	260	807
2011	0.5	0.0	263	808
2012	0.9	0.0	252	748
2013	1.7	0.0	236	674
2014	1.1	0.0	263	718
2015	0.8	0.0	266	716
2016	0.3	0.0	265	588
2017	0.5	0.0	258	474
2018	0.3	0.0	258	475
2019	4.3	0.0	140	261
2020	4.3	0.0	137	255
2021	2.6	0.0	145	270

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Figure 12: Neenah Paper – Michigan, Inc.: Facility-wide Actual and Projected Annual Emission Rates (2004 – 2032)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform (https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform)

Table 18: Neenah Paper – Michigan, Inc.: Facility-wide Actual and Projected Annual Emission Rates (2004 – 2032)

Year	NO_X (tpy)	SO_2 (tpy)
2004	297.5	712.7
2005	296.7	819.9
2006	284.2	782.2
2007	245.3	669.4
2008	262.7	713.2
2009	230.3	696.7
2010	260.8	807.1
2011	263.3	807.6
2012	252.8	748.5
2013	237.4	674.3
2014	264.4	717.6
2015	266.9	716.1
2016	264.9	588.4
2017	258.4	473.6
2018	258.8	474.9
2019	144.6	260.9
2020	141.7	255.2
2021	147.9	270.1
2022	135.78	236.84
2026	124.93	217.89
2032	106.26	184.74

Source: MAERS Annual Pollutant Totals Query https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform (https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform)

3.4 Source Flagged by FLMs but not Selected

During the FLM consultation process, the FLMs recommended EGLE also select EES Coke Battery LLC, Midland Cogeneration Venture, L'Anse Warden Electric Company, and US Steel Great Lakes Works for further analysis. As show in Table 8, emissions for these sources were below the pollutant specific unit Q/d>6 threshold and beyond EGLE's 80 percent target. Each of these facilities had Q/d on a facility-wide basis for the sum of NH_3, NO_X, $PM_{2.5}$, and SO_2 of 6.2 or less, except for Midland Cogeneration Venture, which had a facility-wide Q/d of 11.6.

Since the facility-wide Q/d for Midland Cogeneration Venture was higher relative to the other three facilities recommended by the FLMs, EGLE provides additional information below to describe the units, emission rates, and emission controls at Midland Cogeneration Venture without making an assessment as to whether the existing controls or new controls would be necessary to make reasonable progress.

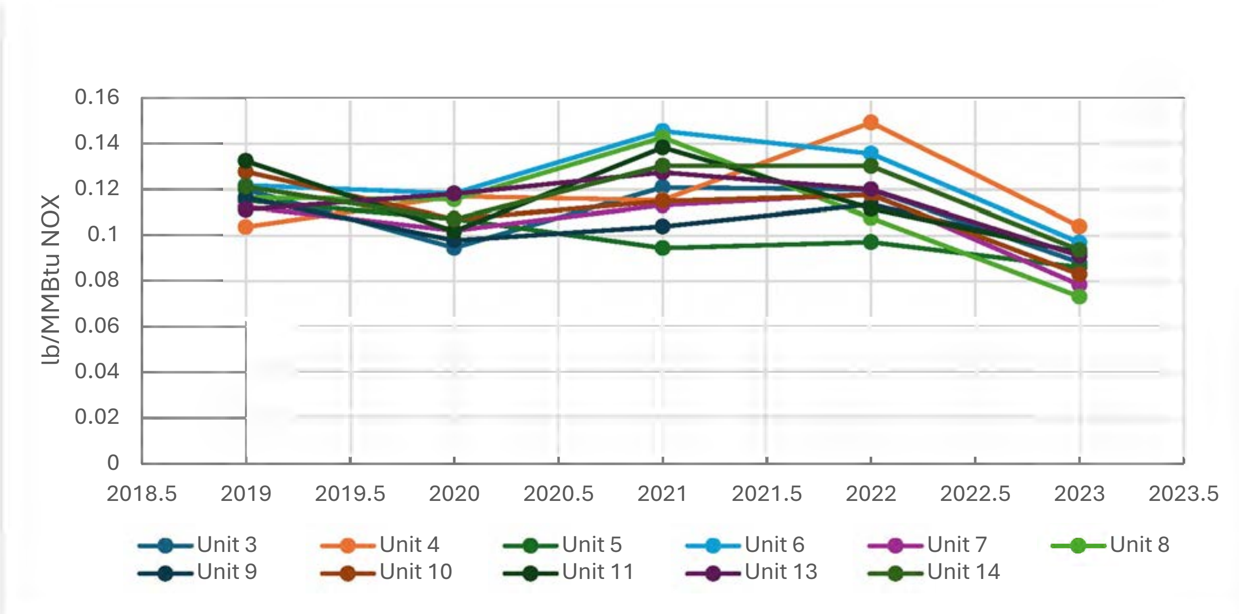
3.4.1 Midland Cogeneration Venture

There are 11 emission units at Midwest Cogeneration Venture that comprise the facility-wide Q/d of 11.6 based on emissions of NH_3, NO_X, $PM_{2.5}$, and SO_2. Each of the emission units has a pollutant specific unit Q/d of 1.0 to 1.1 for NO_X and almost zero for SO_2. These 11 emission units are combined cycle gas turbines fueled by pipeline natural gas.

Each unit uses steam injection to control NO_X emissions in a process where steam is introduced into the combustor, lowering the flame temperature of the combustion reaction and, in turn, lowering the thermal production and output of NO_X.

Over the most recent 5-year period from 2019 – 2023, NO_X emission rates from the USEPA's Clean Air Markets Program Data (CAMPD) are depicted in Figure 13 and Table 19 below.

Figure 13: Midland Cogeneration Venture: Trends in Unit Annual Emission Rates (2019 – 2023)



Source: Clean Air Markets Program Data
https://campd.epa.gov/

Table 19: Midland Cogeneration Venture: Trends in Unit Annual Emission Rates (2019 – 2023)

YEAR	Annual Emission Rate NO_X (lb/MMBtu)										
UNIT ID	3	4	5	6	7	8	9	10	11	13	14
2019	0.120	0.104	0.115	0.122	0.113	0.117	0.117	0.128	0.133	0.111	0.121
2020	0.095	0.117	0.107	0.118	0.102	0.116	0.098	0.107	0.102	0.118	0.107
2021	0.121	0.115	0.095	0.146	0.113	0.143	0.104	0.115	0.138	0.128	0.130
2022	0.120	0.149	0.097	0.136	0.118	0.108	0.114	0.118	0.112	0.120	0.130
2023	0.088	0.104	0.086	0.097	0.079	0.073	0.092	0.083	0.093	0.091	0.094

Source: Clean Air Markets Program Data
https://campd.epa.gov/

3.5 Sources Selected for Four-factor Analysis

As documented in Section 3.3.1 above, using the pollutant specific unit Q/d>6 threshold, EGLE screened out units that had retired or have enforceable mechanisms to retire by 2028. EGLE also addressed a source that has been indefinitely idled in Section 3.3.2. Then, in Section 3.3.3, EGLE screened out units with existing effective control measures. With three remaining sources, EGLE then proceeded with four-factor analysis for specific units at the following three facilities:

Table 20: Units Selected for a Four-factor Analysis

Facility Name	Sector	Facility Unit ID	Q/d Unit (sum)	Q/d NO_X	Q/d SO_2	Q/d Facility (sum)
TILDEN MINING COMPANY LC	NON-EGU	EU Kiln 2–gas fired	42.8	42.3	0.0	108.6
		EU Kiln 2–coal fired	12	11.0	0.9	
Verso Escanaba LLC (Now Billerud Escanaba LLC)	NON-EGU	Recovery Furnace 10	7.2	3.1	0.1	22.5
		No. 11 Power Boiler	12.7	3.0	3.4	
GRAYMONT WESTERN LIME, INC.	NON-EGU	EU Kiln 1	8.1	7.1	0.5	8.1

3.6 Documentation of the Source Selection Process and Result

As described above in Section 2, EGLE identified Class I areas where Michigan contributes more than 1 percent to the 2028 modeled total light extinction based on LADCO's 2028 modeled projections using the 2016 base year and responded to MANE-VU's asks regarding Class I areas affected outside Michigan.

In Section 3.1, EGLE determined which pollutants to consider for an evaluation of control measures based on the analyses in LADCO's 2021 Technical Support Document of the IMPROVE monitoring data, which found that NO_X and SO_2 emissions lead to the formation of the particulate species of nitrate and sulfate that currently contribute more to visibility impairment in the LADCO region Class I areas than $PM_{2.5}$, NH_3, and VOC.

Under Section 3.2, EGLE estimated baseline visibility impacts for source selection by relying on LADCO's Q/d analysis. EGLE identified over 80 units with Q/d of 1.0 or greater using a 2016 base year, including NH_3, NO_X, $PM_{2.5}$, and SO_2 in the summation of 'Q' and the closest Class I area to the sources for the value of 'd.'

As recommended in the 2019 Regional Haze Guidance, EGLE then evaluated Q/d metrics on an individual pollutant basis, since inclusion of the other haze precursors ($PM_{2.5}$, VOC, and ammonia) in the Q/d analysis would not reflect NO_X and SO_2 as the dominant species contributing to visibility impairment in the LADCO Class I areas. Additionally, EGLE relied on a unit pollutant level Q/d approach recognizing that the evaluation of control measures would take place at the unit level and that addressing NOx and SO_2 emissions would entail entirely different control systems.

To capture 80 percent of emissions of NO_X and SO_2 collectively, and to identify units for further evaluation and possible four-factor analyses, an incremental evaluation led to a pollutant specific unit Q/d>6 for NO_X and SO_2 separately. A pollutant specific unit Q/d>6 threshold captured 70 percent of NO_X and 85 percent of SO_2 emissions, and 79 percent of both NO_X and SO_2, collectively.

Using the pollutant specific unit Q/d>6 threshold, EGLE first screened out units that had retired or have enforceable mechanisms to retire by 2028 as listed in Section 3.3.1. EGLE identified 44 EGUs from 17 different Michigan power plants that retired during 2016 – 2023, as well as units that have enforceable mechanisms under a Consent Decree to retire:

- Consumers Energy – J.H. Campbell Plant: Units 1, 2, and 3 on or before May 31, 2025.
- Consumers Energy – Dan E. Karn: Units 3 and 4 on or before May 31, 2031

In Section 3.3.2, EGLE also addressed a source that has been indefinitely idled. Then, in Section 3.3.3, EGLE screened out units with existing effective controls and provided weight-of-evidence demonstrations in determining whether those measures were necessary for reasonable progress. With three remaining sources identified, EGLE then proceeded with four-factor analysis for specific units at:

- Billerud Escanaba LLC
- Graymont Western Lime, Inc.
- Tilden Mining Company LC

4. Step 4: CHARACTERIZATION OF FACTORS FOR EMISSION CONTROL MEASURES

Identify potential emission control measures for the selected sources, develop data on the four statutory factors and on visibility benefits if they will be considered. See 40 CFR 51.308(f)(2).

The four statutory factors set out in the Regional Haze Rule are:

- Cost of compliance
- Time necessary for compliance
- Energy and non-air environmental impacts
- Remaining useful life of the source

After having re-done the Q/d analysis used to support the source-selection process within the initial 2021 Regional Haze SIP submittal, EGLE found Billerud Escanaba LLC, Graymont Western Lime, Inc., and Tilden Mining Company LC to meet the criteria for requiring a four-factor analysis to determine whether additional control measures should be implemented to achieve reasonable progress during the second planning period.

EGLE submitted Request for Information (RFI) Letters (*attached in* Appendices 19, 20, and 21) to each of the three reselected sources to gather the source specific four-factor analysis information that was needed for EGLE staff to make a decision on whether to adopt a new control measure into its LTS.

Table 21: Units Selected for a Four-factor Analysis, Pollutant Specific Q/d, and Control Measures Considered

Facility Name	Sector	Facility Unit ID	Q/d NO_X	Q/d SO_2	Control Measures Evaluated
Verso Escanaba LLC (Now Billerud Escanaba LLC)	NON-EGU	No. 11 Power Boiler		3.4	• Fuel Substitution • Dry sorbent injection (DSI) • Dry FGD (dry scrubbing) • Wet FGD (wet scrubbing)
GRAYMONT WESTERN LIME, INC.	NON-EGU	EU Kiln 1	7.1		• SNCR • Selective Catalytic Reduction (SCR)
TILDEN MINING COMPANY LC	NON-EGU	EU Kiln 2 gas-fired	42.3		• Low NO_X Burner (LNB) • Over-fire Air System (OFA) • Fuel Substitution
		EU Kiln 2 coal-fired	11.0		

4.1 Four-factor Analysis: Billerud Escanaba LLC, No. 11 Power Boiler

Billerud Escanaba LLC (formerly Verso Escanaba) was described in detail in Michigan's 2021 Regional Haze SIP Submittal on pages 11, 12, 17, and18 (*See* Appendix 1). This SIP supplement provides a full four-factor analysis (*See* Appendix 22) and further elaboration on EGLE's evaluation of potential control measures necessary for reasonable progress during the second implementation period.

Although the No. 11 Power Boiler had a pollutant specific unit Q/d of 3.4 for SO_2 and 3.0 for NO_X, which was under EGLE's threshold of 6, EGLE selected this unit for a four-factor analysis because the FLMs requested it and because the No. 11 Power Boiler is not subject to SO_2 controls or an SO_2 limit that is equal to or more stringent than SO_2 BACT limits for other similar/identical units.

For NO_X, the No. 11 Power Boiler must maintain compliance with PSD emission limits for NO_X (0.70 lb /MMBtu (30-day rolling average, when firing solid fuels)) in its ROP (MI-ROP-A0884-2021b) (per 40 CFR 52.21) and NO_X limitations established in Part 8 of Michigan's Air Pollution Control Rules (R 336.1801). Additionally, in June 2023, the USEPA finalized its "Good Neighbor Rule" FIP for the 2015 Ozone NAAQS, which included NO_X emissions limitations and control requirements for existing large, multi-fueled boilers (>100 MMBtu/hr) at paper mills that are set to become enforceable at the beginning of the 2026 ozone season.

EGLE found that evaluating and/or pursing additional NO_X control devices would not be necessary at this time since the No. 11 Power Boiler is expected to eventually become subject to a more stringent federal NO_X emissions requirements under the Good Neighbor Rule during the second implementation period (2018 – 2028) of the Regional Haze Rule. Although the Supreme Court recently granted a request to stay the Good Neighbor Rule (*See* Ohio et al v. USEPA et al, Case No. 23A349, Supreme Court of the United States, June 27, 2024), EGLE still considers this as the first option, and will revisit the need to evaluate NO_X controls if the more stringent NO_X emission requirements are not implemented at the federal level.
For SO_2, the No. 11 Power Boiler is currently subject to PSD emission limits for SO_2 (1.2 lb/MMBtu (10-day rolling average, when firing solid fuels)) in its (MI-ROP-A0884-2021b) (per 40 CFR 52.21).

EGLE found it necessary to evaluate and/or pursue SO_2 control devices since the No. 11 Power Boiler is not equipped with abatement technology, nor is it subject to an emissions limitation for SO_2 that is equal to or more stringent than SO_2 BACT limits for other similar/identical units. (*See* RACT/BACT/LAER Clearinghouse Basic Information at https://www.epa.gov/catc/ractbactlaer-clearinghouse-rblc-basic-information.)

In an RFI letter sent to Billerud Escanaba LLC on April 24, 2024, EGLE requested that Billerud Escanaba LLC conduct a four-factor analysis, and submit a subsequent report, of four different types of SO_2 control measures for Billerud Escanaba LLC's No. 11 Power Boiler (*See* Appendix 19).

Billerud Escanaba LLC provided a full four-factor analysis as EGLE requested. Table 22 provides a summary of the four-factor analysis, which is attached as Appendix 22.

Table 22: Summary of Four Factor Analysis for Billerud Escanaba LLC, No. 11 Power Boiler, SO_2 Emissions

Verso Escanaba LLC (Now Billerud Escanaba LLC): No. 11 Power Boiler, SO_2 Emissions				
Control Measures Evaluated	**Cost Effectiveness**	**Time for Compliance**	**Energy and Non-Air Impacts**	**Remaining Useful Life of Source**
Fuel Substitution	\$5,734/ton SO_2	A few months for sale of remaining fuel plus time for new permits.	Annual Energy Usage: NA	Billerud Escanaba LLC plans to continue operation of the No. 11 Power Boiler for the foreseeable future.
DSI	\$10,727/ton SO_2	4 years	Annual Energy Usage: 26,920 MWh/yr New waste streams would result in increased operating costs and additional regulatory requirements.	
Dry FGD (dry scrubbing)	\$22,281/ton SO_2	4 years	Annual Energy Usage: 12,798 MWh/yr New waste streams would result in increased operating costs and additional regulatory requirements.	
Wet FGD (wet scrubbing)	\$30,082/ton SO_2	4 years	Annual Energy Usage: 14,182 MWh/yr New waste streams would result in increased operating costs and additional regulatory requirements. Wastewater generated by wet FGD systems would likely contain metals associated with wood, such as arsenic, beryllium, cadmium, chromium, mercury, lead, selenium, and copper, as well as other pollutants such as cyanide, ammonia, phosphorus, nitrogen, and total suspended solids. Additional wastewater treatment may be required, and these costs have not been quantified within this analysis.	

4.2 Four-factor Analysis: Graymont Western Lime, Inc., EU Kiln 1 – NOX emissions

Graymont Western Lime, Inc., EU Kiln 1 was described in detail in Michigan's 2021 Regional Haze SIP Submittal on pages 12 and 19 (*See* Appendix 1). This SIP supplement provides a full four-factor analysis (*See* Appendix 23) and further elaboration on EGLE's evaluation of potential control measures necessary for reasonable progress during the second implementation period.

Graymont Western Lime, Inc. operates EU Kiln 1 with LNBs and a Low Excess Air Firing System to comply with BACT-PSD emission limits for NO_X (132.6 lb/hr [24-hour rolling average] and 532 tpy [12-month rolling time period]) specified in its most recent PTI (No. 26-04) (per 40 CFR 52.21).

EGLE selected this unit for a four-factor analysis because EU Kiln 1 had a pollutant specific unit Q/d of 7.1 and because this unit has not undergone a BACT review since 2004.

In an RFI letter sent to Graymont Western Lime, Inc. on April 24, 2024, EGLE requested that Graymont Western Lime, Inc. conduct a four-factor analysis, and submit a subsequent report, of three different types of NO_X control measures for Graymont's line 1 rotary preheater lime kiln (EU-Kiln #1). (*See* Appendix 20.)

Graymont Western Lime, Inc. provided a full four-factor analysis as EGLE requested. Table 23 below provides a summary of the four-factor analysis that was prepared by Trinity Consultants, which is attached as Appendix 23.

Table 23: Summary of Four-Factor Analysis for Graymont Western Lime, Inc., EU Kiln 1, NO_X Emissions

Graymont Western Lime, Inc.: EU Kiln 1, NO_X Emissions				
Control Measures Evaluated	**Cost Effectiveness**	**Time for Compliance**	**Energy and Non-Air Impacts**	**Remaining Useful Life of Source**
Fuel Substitution	NA	NA	NA There is insufficient natural gas supply in the region, and switching fuels would not appreciably improve NO_X emissions.	The remaining useful life of EU Kiln 1 is anticipated to be at least as long as the capital cost recovery period for the measures evaluated.
SCR	$14,433/ton NO_X	3 years	Electricity Cost: $75,821 The additional electrical demand is an energy intensive process that also generates high amounts of greenhouse gases.	
SNCR	$16,372/ton NO_X	3 years	Electricity Cost: $2,517 The additional electrical demand is an energy intensive process that also generates high amounts of greenhouse gases.	

4.3 Four-factor Analysis: Tilden Mining Company LC, EU Kiln 2 – NO_X emissions

Tilden Mining Company LC, Kiln 2 was described in detail in Michigan's 2021 Regional Haze SIP Submittal on pages 12 and 19 (*See* Appendix 1). This SIP supplement provides a full four-factor analysis (*See* Appendices 24 and 25) and further elaboration on EGLE's evaluation of potential control measures necessary for reasonable progress during the second implementation period.

Kiln 2 is identical to Kiln 1; however, it was not subject to the NO_X limits set under the 2016 Revised Taconite BART FIP like Kiln 1. This is due to Kiln 2 being installed in 1978 and therefore not considered as a BART unit during the first planning period. (*See* 81 FR 21672, April 12, 2016: Taconite Federal Implementation Plan Establishing BART for Taconite Plants, https://www.govinfo.gov/content/pkg/FR-2016-04-12/pdf/2016-07818.pdf.)

EGLE selected this unit for a four-factor analysis because EU Kiln 2 had a pollutant specific unit Q/d of 53.3 and because Kiln 2 does not operate NO_X abatement technology and is not subject to NO_X emission limits under PSD, Michigan's Part 8 rules, or any federal program.

In an RFI letter sent to Tilden Mining Company LC on April 24, 2024, EGLE requested that the company conduct a four-factor analysis, and submit a subsequent report, of three different types of NO_X control measures for the company's line 2 indurating (grate/kiln) furnace (EU KILN 2) (*See* Appendix 21).

Tilden Mining Company LC provided a full four-factor analysis as EGLE requested. Table 24 provides a summary of the four-factor analysis that was prepared by Barr Engineering Co., which is attached as Appendices 24 and 25.

Table 24: Summary of Four-Factor Analysis for Tilden Mining Company LC, EU Kiln 2, NO_X Emissions

Tilden Mining Company LC: Kiln 2 – NO_X emissions				
Control Measures Evaluated	**Cost Effectiveness**	**Time for Compliance**	**Energy and Non-Air Impacts**	**Remaining Useful Life of Source**
Fuel Substitution	$2,645/ton NO_X	3 years	The switch from natural gas to coal would result in increased truck traffic and greenhouse gas emissions as well as SO_2 emissions.	The remaining useful life of EU Kiln 2 is anticipated to be at least as long as the control measures evaluated.
LNB	$694/ton NO_X	5 years	LNB can increase CO and VOC emissions.	
OFA	NA	NA	NA OFA is technically infeasible for Kiln 2 as the NO_X formation front is not stationary in an indurating furnace. Therefore, OFA is not included in this analysis.	

5. Step 5: DECISIONS ON WHAT CONTROL MEASURES ARE NECESSARY TO MAKE REASONABLE PROGRESS

Consider the four statutory factors, the five required factors listed in section 51.308(f)(2)(iv) (if not already considered when selecting sources), and, optionally, visibility benefits, and decide on emission controls for incorporation into the LTS. Consider measures adopted by other contributing states, including all measures that have been agreed upon through interstate consultation. See 40 CFR 51.308(f)(2).

5.1 Evaluation of the Four Statutory Factors

The four statutory factors set out in the Regional Haze Rule are:

- Cost of compliance
- Time necessary for compliance
- Energy and non-air environmental impacts
- Remaining useful life of the source.

Of the four statutory factors, characterizing the cost of compliance relied upon previous regulatory impact analyses for both federal and state rules. To facilitate Michigan's decision in considering a cost-effectiveness threshold of potential new add-on controls that would promote Michigan's efforts in setting reasonable progress goals for the second implementation period, past findings of cost-effectiveness thresholds for various emission control technologies were informative. The following sources served as possible reference points from other CAA requirements for similar existing point sources, which included the following cost per ton thresholds for pollutant control, as listed without adjustment for inflation:

- **Revised Cross-State Air Pollution Rule (CSAPR) Update for the 2008 Ozone NAAQS:**
  $1,800/ton

  Source: "Regulatory Impact Analysis for the Final Revised Cross-State Air Pollution Rule (CSAPR Update for the 2008 Ozone NAAQS," EPA-452/R-21-002, March 2021, https://www.epa.gov/sites/default/files/2021-03/documents/revised_csapr_update_ria_final.pdf.

- **Regional Haze – Best Available Retrofit Technology (BART) for SO_2:**
  $400 - $2000/ton

  Source: 70 FR 39132, July 6, 2005, https://www.govinfo.gov/content/pkg/FR-2005-07-06/pdf/05-12526.pdf.

- **Michigan NO_X Reasonably Available Control Technology (RACT):**
  $400 - $1600/ton

  Source: Michigan Office of Administrative Hearings and Rules, Administrative Rules Division, "Regulatory Impact Statement and Cost-Benefit Analysis," regarding Emission Limitations and Prohibitions – Oxide of Nitrogen.

  Source: ARS Public - RFR Transaction

- **EGU NO_X Mitigation Strategies Final Rule:**
  $6,700/ton
  for SNCR retrofit for coal units less than 100 MW lacking post-combustion NO_X control technology.

  Source: Technical Support Document for the Final Federal Good Neighbor Plan for the 2015 Ozone National Ambient Air Quality Standards," USEPA, Office of Air and Radiation, March 2023, https://www.epa.gov/system/files/documents/2023-03/EGU%20NOX%20Mitigation%20Strategies%20Final%20Rule%20TSD.pdf.

- **Good Neighbor Plan for the 2015 8-hour Ozone NAAQS:**
  $1,800/ton ($2016)
  for optimizing existing NO_X Controls and installing state-of-the art combustion controls.
  $11,000/ton ($2016)
  for installation of SCR and SNCR post-combustion controls for coal units of 100 MW or greater capacity that do not have post-combustion NO_X control technology.
  $7,500/ton
  for the purposes of the non-EGU screening assessment.

  Source: 88 FR 36654, June 5, 2023, https://www.govinfo.gov/content/pkg/FR-2023-06-05/pdf/2023-05744.pdf.

  "Economic Impact Assessment for the Proposed Supplemental Federal "Good Neighbor Plan" Requirements for the 2015 8-hour Ozone National Ambient Air Quality Standard," USEPA, Office of Air Quality Planning and Standards, Health and Environmental Impacts Division, November 2023, https://www.epa.gov/system/files/documents/2024-01/san-11159_gn-plan-supplemental-proposed-eia_231218_eo-12866-clearance2_clean.pdf.

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TABLE V.C.2–3—BY INDUSTRY, EMISSIONS UNIT TYPE, ASSUMED CONTROL TECHNOLOGIES, AND ESTIMATED AVERAGE COST PER TON BY CONTROL TECHNOLOGY ACROSS ALL NON-EGU EMISSIONS UNITS

Industry/industries	Emissions unit type	Assumed control technologies that meet final emissions limits	Average cost/ton values (2016$)
Pipeline Transportation of Natural Gas	Reciprocating Internal Combustion Engine	NSCR or Layered Combustion, Layered Combustion, SCR, NSCR.	4,981
Cement and Concrete Product Manufacturing	Kiln	SNCR	1,632
Iron and Steel Mills and Ferroalloy Manufacturing	Reheat Furnaces	LNB	3,656
Glass and Glass Product Manufacturing	Furnaces	LNB	939
Iron and Steel Mills and Ferroalloy Manufacturing	Boilers	SCR or LNB + FGR	8,369
Metal Ore Mining			14,595
Basic Chemical Manufacturing			11,845
Petroleum and Coal Products Manufacturing			14,582
Pulp, Paper, and Paperboard Mills			14,134
Solid Waste Combustors and Incinerators	Combustors or Incinerators	ANSCR or LN™ and SNCR	7,836
Overall Average Cost/Ton			5,339

- On June 27, 2024, the Supreme Court granted states and industry applicants' request to stay the USEPA's Good Neighbor Rule for the 2015 8-hour Ozone NAAQS while legal challenges continue, including arguments from states and industry groups regarding costs. *See* Ohio et al v. USEPA et al, Case No. 23A349, Supreme Court of the United States, June 27, 2024.
  Source:
  https://www.supremecourt.gov/opinions/23pdf/23a349_0813.pdf
  https://www.scotusblog.com/2024/06/supreme-court-blocks-epas-good-neighbor-air-pollution-rule/.

5.1.1 Determination of Measures Necessary to Make Reasonable Progress

When evaluating the results of a four-factor analysis, the 2021 Clarifications Memo explains,

> "When the outcome of a four-factor analysis is a new measure, that measure is needed to remedy existing visibility impairment and is necessary to make reasonable progress. When the outcome of a four-factor analysis is that no new measures are reasonable for a source, the source's existing measures are generally needed to prevent future visibility impairment; i.e., to prevent future emission increases; and thus necessary to make reasonable progress. Measures that are necessary to make reasonable progress must be included in the SIP. However, there may be circumstances in which a source's existing measures are not necessary to make reasonable progress." (2021 Clarifications Memo, Section 4.1.)

As described in Section 3.3 above, to support a determination that a source's existing measures are not necessary to make reasonable progress, the USEPA described a weight-of-evidence approach based on the source's most recent 5-year historical emission rate, projected emissions and emission rate, and enforceable limits related to its existing measures to demonstrate that "the source has consistently implemented its existing measures and has achieved, using those measures, a reasonably consistent emission rate" that will not increase in the future. *See* 2021 Clarifications Memo, Section 4.1.

EGLE's evaluation of each of the four-factor analyses is presented below.

5.1.2 Billerud Escanaba LLC, No. 11 Power Boiler, SO_2

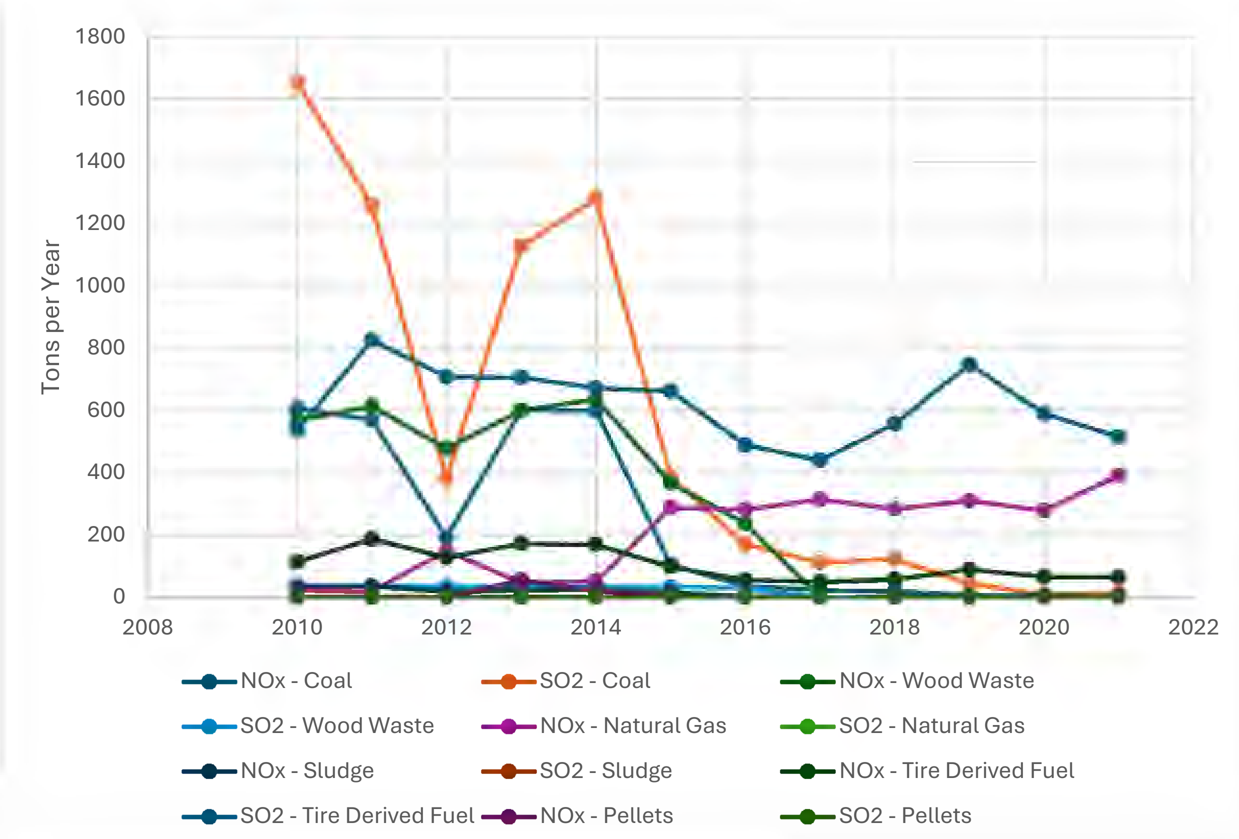
EGLE considered each of the four statutory factors in evaluating the outcome of the four-factor analysis that was performed for Billerud Escanaba LLC, No. 11 Power Boiler. The time to compliance would be achievable by 2028 within the remainder of the second implementation period. The remaining useful life of the No. 11 Power Boiler does not appear to be a limiting factor since Billerud Escanaba LLC plans to continue operation into the foreseeable future. However, the energy and non-air impacts would impose significant drawbacks resulting from additional power consumption, waste production, and wastewater compliance issues, including additional costs not captured in the cost-effectiveness estimations for potential new controls.

The cost-effective values found under the CSAPR, BART, and RACT rulemakings generally establish a lower frame of reference compared to the higher values in the Good Neighbor Rule that was stayed by the Supreme Court. Relying on references to the currently implemented USEPA rules as a rough threshold for what could be considered cost-effective for point sources in Michigan for the second implementation period, the cost-effectiveness values determined in the four-factor analysis for Billerud Escanaba LLC were found to be considerably outside those ranges.

Based on the data pertaining to the cost-effectiveness ($/ton of SO_2 abatement) of implementing and/or retrofitting the No. 11 Power Boiler with the four different SO_2 control mechanisms, it was found that all options surpass the 'cost-effectiveness' values under other currently implemented USEPA rules described in Section 5.1 above, which EGLE considered for determining whether a control measure is necessary for reasonable progress. While there are drawbacks to the energy and non-air impacts factor, cost-effectiveness was the most decisive factor, and EGLE was able to eliminate all four SO_2 control options evaluated as being necessary to make reasonable progress through adoption into Michigan's LTS.

Just as no new measures were found necessary to make reasonable progress, EGLE has found that the existing measures for the No. 11 Power Boiler are also not necessary to make reasonable progress. Consistent with the demonstration described in the 2021 Clarifications Memo in Section 4.1, Tables 25 and 26 and Figures 14 and 15 below illustrate the reasonably consistent and declining trends in facility-wide actual NO_X and SO_2 emissions for No. 11 Power Boiler from 2010 – 2021. Additionally, Figure 15 and Table 26 illustrate the expectation that the unit's emission rate will not increase in the future based on projected emissions from the facility as a whole through 2032 using the USEPA's 2022v1 Emissions Modeling Platform. Based on the No. 11 Power Boiler's existing measures and enforceable requirements described above as well as the most recent 5 years of emission rate data available provided below, Billerud Escanaba LLC is projected to continue to implement the existing measures for the No. 11 Power Boiler and not to increase its emission rate. As such, EGLE has determined that the existing measures are not necessary to include in the LTS or the regulatory portion of the SIP to prevent future emission increases and future visibility impairment.

Figure 14: Billerud Escanaba LLC, No. 11 Power Boiler Annual Emissions (2010 – 2021)



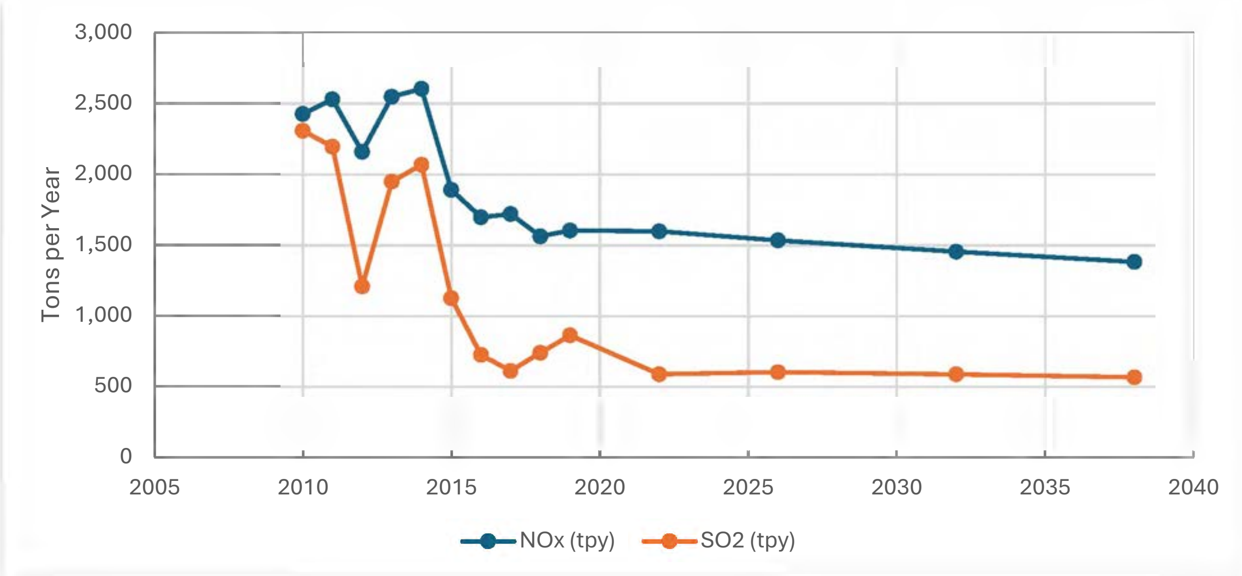
Source: MAERS Annual Pollutant Total Query https://www.egle.state.mi.us/maers/emissions_query.asp

Table 25: Billerud Escanaba LLC, No. 11 Power Boiler: Annual Emissions (2010 – 2021)

Year	NO_X - Coal	SO_2 - Coal	NO_X - Wood Waste	SO_2 - Wood Waste	NO_X - Natural Gas	SO_2 - Natural Gas	NO_X - Sludge	SO_2 - Sludge	NO_X - Tire Derived Fuel	SO_2 - Tire Derived Fuel	NO_X - Pellets	SO_2 - Pellets
2010	606	1657	567	35	24	0	35	2	114	537	0	0
2011	570	1260	614	36	18	0	35	2	187	826	0	0
2012	192	380	478	35	148	0	18	1	127	708	0	0
2013	601	1128	600	33	47	0	24	1	171	705	55	3
2014	599	1281	636	33	51	0	25	1	169	672	21	1
2015	104	386	367	33	288	1	15	1	97	662	1	0
2016	35	170	236	28	281	1	3	0	54	489	0	0
2017	23	111	0	0	314	1	0	0	49	439	0	0
2018	19	122	0	0	283	1	3	0	57	557	0	0
2019	6	43	0	0	309	1	4	1	88	748	0	0
2020	3	9	0	0	278	1	6	1	65	589	0	0
2021	5	14	0	0	391	1	2	0	63	515	0	0

Source: MAERS Annual Pollutant Total Query https://www.egle.state.mi.us/maers/emissions_query.asp

Figure 15: Billerud Escanaba LLC: Facility-wide Actual and Projected Emissions (2010 – 2032)



Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

Table 26: Billerud Escanaba LLC: Facility-wide Actual and Projected NO_X and SO_2 Emissions (2010 – 2032)

Year	NO_X (tpy)	SO_2 (tpy)
2010	2,428	2,309
2011	2,530	2,196
2012	2,160	1,210
2013	2,549	1,950
2014	2,605	2,069
2015	1,892	1,127
2016	1,699	727
2017	1,721	614
2018	1,564	742
2019	1,605	865
2022	1,599	591
2026	1,535	605
2032	1,455	590

Source: MAERS Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

5.1.3 Graymont Western Lime, Inc., EU Kiln 1 – NO_X emissions

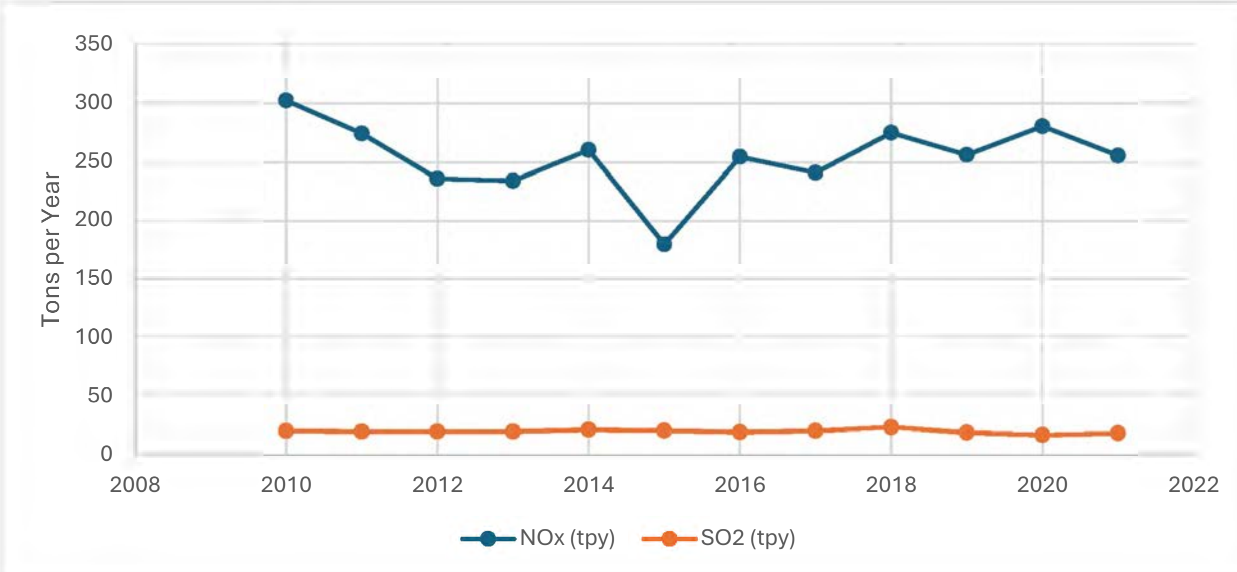
EGLE considered each of the four statutory factors in evaluating the outcome of the four-factor analysis that was performed for Graymont Western Lime, Inc., EU Kiln 1. The time to compliance would be achievable by 2028 within the remainder of the second implementation period. The remaining useful life of the EU Kiln 1 does not appear to be a limiting factor since Graymont Western Lime, Inc. plans to continue operation into the foreseeable future. However, the energy and non-air impacts would impose significant drawbacks resulting from additional power consumption and greenhouse gas production, including additional costs not captured in the cost-effectiveness estimations for potential new controls.

The cost-effective values found under the CSAPR, BART, and RACT rulemakings generally establish a lower frame of reference compared to the higher values in the Good Neighbor Rule that was stayed by the Supreme Court. Relying on references to the currently implemented USEPA rules as a rough threshold for what could be considered cost-effective for point sources in Michigan for the second implementation period, the cost-effective values determined in the four-factor analysis for Graymont Western Lime, Inc., EU Kiln 1 were found to be considerably outside those ranges.

Based on the data pertaining to the cost-effectiveness ($/ton of NO_X abatement) of implementing and/or retrofitting EU Kiln #1 with the three different NO_X control mechanisms, it was found that two options, SCR and SNCR, surpass the ‘cost-effectiveness’ described in Section 5.1 that EGLE considered for determining whether a control measure is necessary for reasonable progress. The remaining control option (fuel substitution from coal to natural gas usage) was determined to have either a minimal, or potentially unfavorable, impact on total annual NO_X emissions. With the drawbacks to the energy and non-air impacts and cost-effectiveness factors as well as the impracticability of fuel substitution, EGLE was able to eliminate all three NO_X control mechanisms as being necessary to make reasonable further progress through adoption into Michigan’s LTS.

Just as no new measures were found necessary to make reasonable progress, EGLE has found that the existing measures for EU Kiln 1 are also not necessary to make reasonable progress. Consistent with the demonstration described in the 2021 Clarifications Memo in Section 4.1, Tables 27 and 28, and Figures 16 and 17 illustrate the reasonably consistent and declining trends in facility-wide actual NO_X and SO_2 emissions for EU Kiln 1 from 2010 – 2021. Additionally, Figure 17 and Table 28 illustrate the expectation that the unit’s emission rate will not increase in the future based on projected emissions from the facility as a whole through 2032 using the USEPA’s 2022v1 Emissions Modeling Platform. Based on EU Kiln 1’s existing measures and enforceable requirements described above as well as the most recent 5 years of emission rate data available provided below, Graymont Western Lime, Inc. is projected to continue to implement the existing measures for EU Kiln 1 and not to increase its emission rate. As such, EGLE has determined that the existing measures are not necessary to include in the LTS or the regulatory portion of the SIP to prevent future emission increases and future visibility impairment.

Figure 16: Graymont Western Lime, Inc., EU Kiln 1: Annual Emission Rates (2010 – 2021)



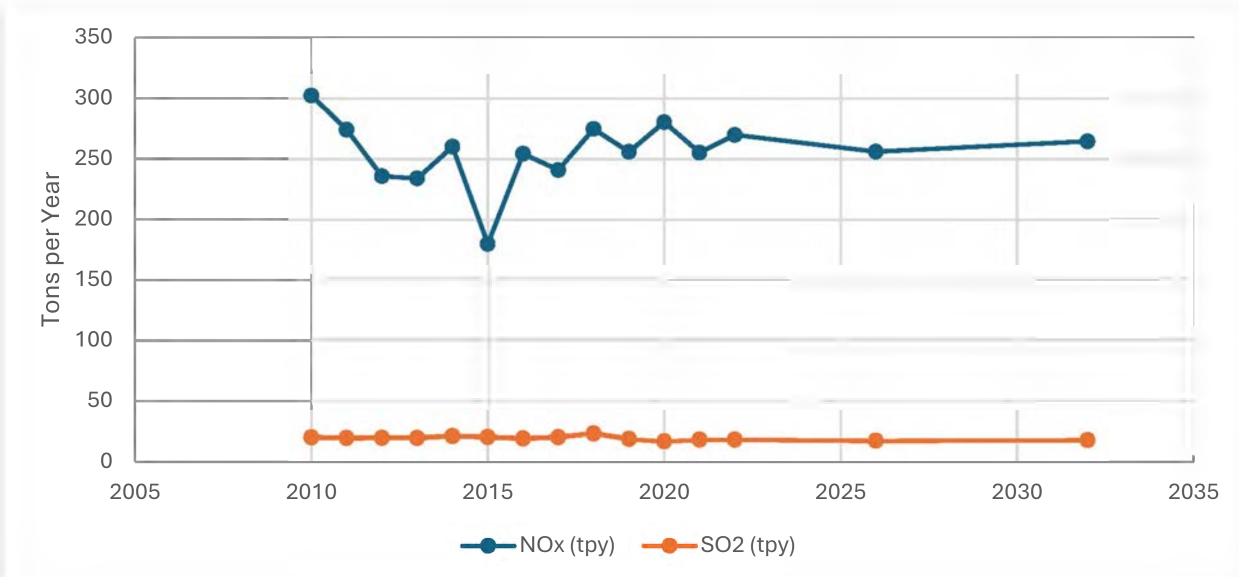
Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 27: Graymont Western Lime, Inc., EU Kiln 1: Annual Emission Rates (2010 – 2021)

Year	NO_X (tpy)	SO_2 (tpy)
2010	302.51	20.58
2011	274.36	19.99
2012	235.97	20.07
2013	234.1955	20.04
2014	260.3325	21.63
2015	180.2	20.76
2016	254.48	19.57
2017	241.09	20.67
2018	274.969	23.721
2019	256.1	19.14
2020	280.5	17.18
2021	255.532	18.616

Source MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Figure 17: Graymont Western Lime, Inc.: Facility-wide Actual and Projected NO_X and SO_2 Emissions (2010 – 2032)



Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

Table 28: Graymont Western Lime, Inc.: Facility-wide Actual and Projected NO_X and SO_2 Emissions (2010 – 2032)

Year	NO_X (tpy)	SO_2 (tpy)
2010	302.5	20.58
2011	274.4	19.99
2012	236	20.07
2013	234.2	20.04
2014	260.3	21.63
2015	180.2	20.76
2016	254.5	19.57
2017	241.1	20.67
2018	275	23.72
2019	256.1	19.14
2020	280.5	17.18
2021	255.5	18.62
2022	270	18.68
2026	256.23	17.73
2032	264.72	18.31

Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

5.1.4 Tilden Mining Company LC, EU Kiln 2

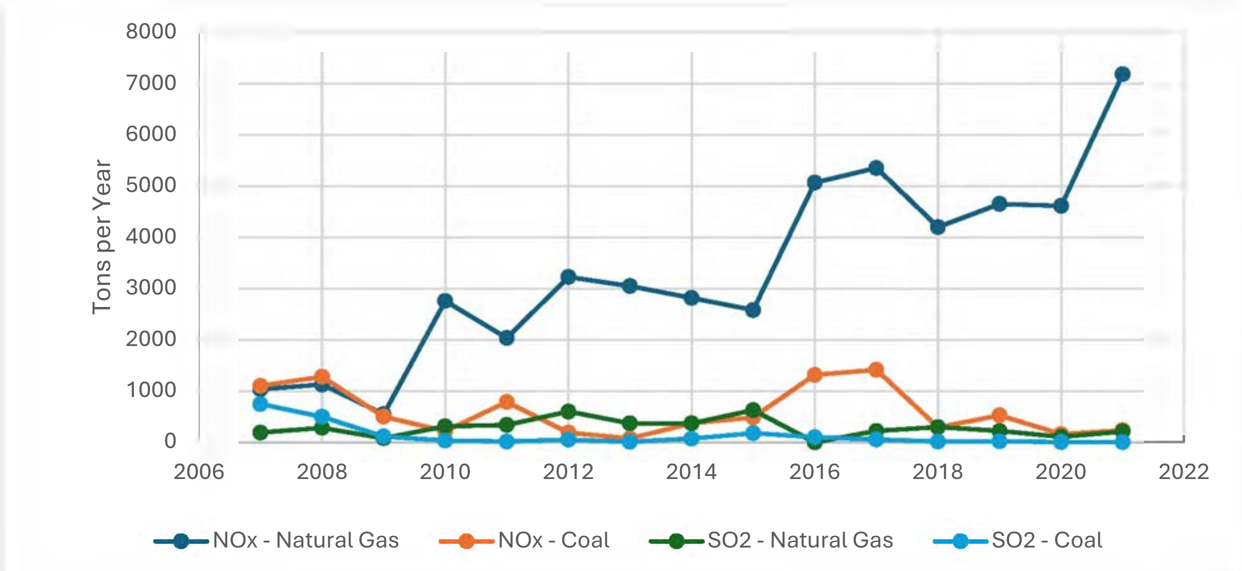
Based on the provided information pertaining to the technical feasibility of implementing and/or retrofitting EU KILN 2 with the three different NO_X control mechanisms, it was found that one option (overfire air system) is technically infeasible for EU KILN 2, as the NO_X formation front is not stationary in an indurating furnace. This option was therefore removed from further analysis. Additionally, the fuel substitution option for EU KILN 2 was found to be inadequate by both Tilden Mining Company LC and EGLE for the purposes of reducing visibility impairment at Michigan's Class I areas considering that natural gas would need to be replaced by solid fuel (coal), which would result in higher SO_2 emissions – although NO_X emissions would be reduced. The remaining control option (low NO_X burner technology) was determined to be technically feasible and cost-effective; however, through a visibility and emissions modeling analysis (as shown on pgs. 17-22 in Appendices 24 and 25), Tilden Mining Company LC concluded that any significant reduction in NO_X emissions from the company's EU KILN 2 would likely result in a negligible visibility improvement at both Isle Royale and Seney. It was also noted in the company's four-factor analysis report that "LNB technology would require significant resources and a time period of approximately five years to engineer, permit, and install the equipment," (as shown on pgs. 14-15 in Appendices 24 and 25). If EGLE were to revise its 2021 Regional Haze SIP to include a more stringent NO_X limit based on the reduction capacity and application of LNB technology to EU KILN 2 and submit this revision to the USEPA in early 2025, EGLE recognizes that the engineering, permitting, and installation of the LNB technology for EU KILN 2 would not be complete until at least 2030 – well into the third planning period of the Regional Haze Program. Through these evaluations and determinations, EGLE was able to eliminate all three NO_X control mechanisms as being necessary to make reasonable further progress through adoption into Michigan's LTS.

EGLE is also relying on the additional justification provided in the following subsection (5.2) to support its determination that LNB technology for EU KILN 2 does not need to be incorporated into Michigan's LTS in order to make reasonable further progress towards "natural visibility conditions" at either Seney National Wildlife Refuge or Isle Royale National Park during the second planning period. The justification (*see* pg. 60) also bolsters EGLE's decision that an additional control measures evaluation (four-factor analysis) for EU KILN 1 would not be appropriate to conduct during this planning period.

The four-factor analysis by Barr Engineering Co. notes, "The estimated 2028 baseline NO_X emissions for this evaluation is 9,005 tpy for Kiln 2. The 2028 baseline emission assumes a production rate of 4,000,000 long-tons of pellets and emissions assuming natural gas firing. Tilden Mining Company LC determined the projected 2028 production rate by reviewing 2000 through 2023 facility-wide (Kiln 1 and Kiln 2) production rates and distributing production equally across each kiln." (*See* Appendices 24 and 25)

Tables 29 and 30 and Figures 18 and 19 below depict the annual emission rates for EU Kiln 2 from 2007 – 2021, as well as the actual and projected emissions for the overall facility from 2010 – 2032.

Figure 18: Tilden Mining Company LC, EU Kiln 2: Annual Emission Rates for NO_X and SO_2 (2007–2021)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 29: Tilden Mining Company LC, EU Kiln 2: Annual Emission Rates for NO_X and SO_2 (2007–2021)

Year	NO_X - Natural Gas	NO_X - Coal	SO_2 - Natural Gas	SO_2 - Coal
2007	1040	1108	195	752
2008	1133	1285	288	504
2009	554	507	84	118
2010	2762	221	317	39
2011	2040	792	344	21
2012	3231	194	605	56
2013	3053	80	375	15
2014	2821	378	375	77
2015	2586	490	633	185
2016	5071	1321	3	105
2017	5357	1419	227	60
2018	4204	297	302	21
2019	4657	531	228	26
2020	4618	164	111	10
2021	7188	241	217	10

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Figure 19: Tilden Mining Company LC: Facility-wide Actual and Projected NO_X and SO_2 Emissions (2007 – 2032)

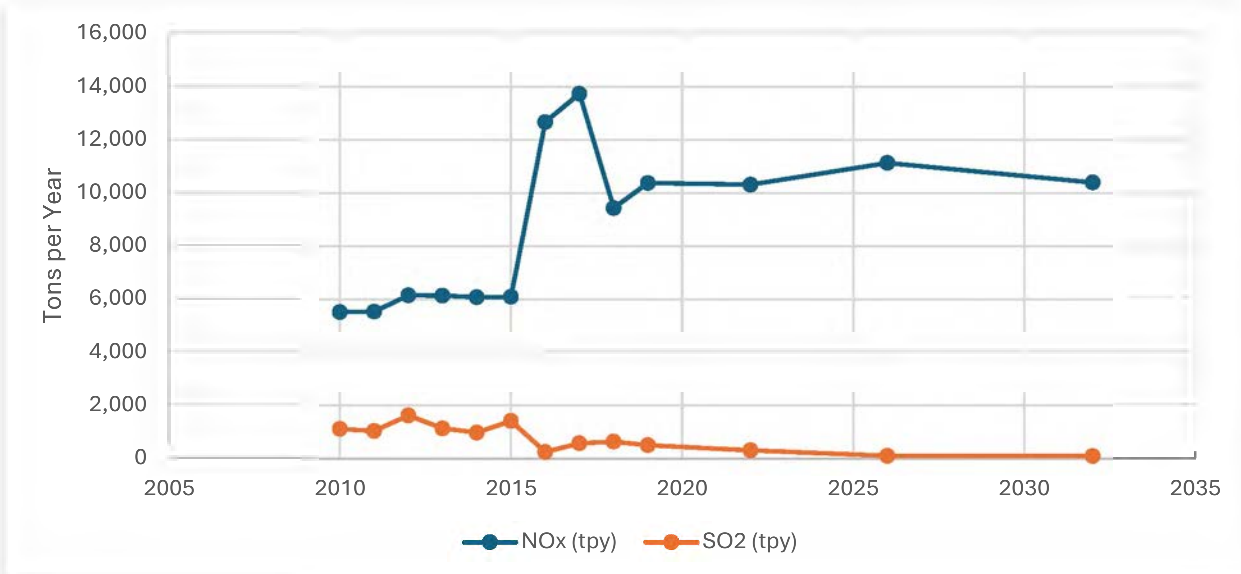


Table 30: Tilden Mining Company LC: Facility-wide Actual and Projected NO_X and SO_2 Emissions (2007–2032)

Year	NO_X (tpy)			SO_2 (tpy)		
	Natural Gas	Coal	Total	Natural Gas	Coal	Total
2007	1039.93	1108.31	2148.24	194.95	751.52	946.47
2008	1133.23	1284.70	2417.93	288.30	503.75	792.05
2009	554.49	506.95	1061.44	84.08	118.48	202.57
2010	2762.09	220.62	2982.71	316.89	39.01	355.90
2011	2040.07	791.87	2831.94	343.87	20.78	364.65
2012	3230.56	193.59	3424.15	605.16	55.89	661.06
2013	3053.04	80.38	3133.42	374.55	15.20	389.75
2014	2821.20	377.71	3198.91	375.33	77.45	452.79
2015	2585.75	490.47	3076.22	633.20	185.12	818.32
2016	5071.28	1320.57	6391.85	3.26	105.44	108.70
2017	5357.45	1419.12	6776.57	227.13	60.17	287.30
2018	4204.20	296.66	4500.86	301.67	21.29	322.96
2019	4656.55	531.35	5187.91	227.57	25.97	253.54
2020	4618.21	163.90	4782.11	111.22	9.89	121.11
2021	7187.87	240.93	7428.80	216.71	9.94	226.65
	TOTAL NO_X (tpy)			TOTAL SO_2 (tpy)		
2022			10,320			310.45
2026			11,136			101.37
2032			10,400			94.56

Source: MAERS Annual Pollutant Total Query
https://www.egle.state.mi.us/maers/emissions_query.asp

USEPA's 2022v1 Emissions Modeling Platform
https://www.epa.gov/air-emissions-modeling/2022v1-emissions-modeling-platform

5.2 Updates to Michigan's Long-term Strategy: Establishing emission limitations, compliance schedules, and other measures necessary to make reasonable progress

EGLE initially addressed its LTS in Michigan's 2021 Regional Haze SIP submittal on pages 22 – 23 (*See* Appendix 1).

EGLE further developed Michigan's LTS after additional consideration of the ambient data, Michigan's contribution to visibility impairment at Class I areas within and outside of the state, the selection of sources for evaluation, the statutory four factors, and EGLE's determination of control measures necessary to make reasonable progress as documented in this SIP Supplement.

Given these considerations, EGLE concludes that the following on-the-books and on-the-way controls in Table 31 below are the measures necessary to make reasonable progress in the second implementation period. All of these controls are already federally enforceable.

The determination that the vast number of retirements at Michigan EGUs (*as shown* in Table 31) that have occurred - and will occur - during the second planning period are the only measures necessary to make reasonable progress towards "natural visibility conditions" through adoption into Michigan's LTS is supported by the refining language included within the 2021 Clarifications Memo, which states "another potentially reasonable approach might be for a state that identifies cost-effective new controls at a multitude of sources to choose to require controls at only a subset of those sources that constitute the vast majority of the visibility benefit. In this case, the state could rely on visibility benefits to prioritize which sources would receive new controls," (*See* 2021 Clarifications Memo, pg. 13.). Based on the 2016 emissions inventory, Michigan EGU retirements that have already occurred during the second implementation period between 2018 and 2024 account for reductions amounting to 17,417 tpy (NO_X) and 42,655 tpy (SO_2), which Michigan concludes constitutes the vast majority of the visibility benefit that could be achieved even with the application of additional new control measures on units that comprise any individual source category.

At the source category (sector) level, those facilities that can be grouped under code 221112 (Fossil Fuel Electric Power Generation) of the 2022 North American Industry Classification System (NAICS)[5] – also known as Fuel Combustion Electric Utilities (EGUs) – constituted the largest percentage of the total statewide emissions of NOx and SO_2 in 2016 (*see* Table 8). EGLE inferred that, due to the shear amount of NOx and SO_2 emissions from the EGU sector, that the vast majority of the anthropogenic visibility impairment at Seney and Isle Royale measured at the beginning of the second planning period could be attributed to this sector as well. EGLE also determined that out of all sectors classified under the NAICS, the application of control measures to those facilities that fell under the Fossil Fuel Electric Power Generation source category would lead to the greatest overall improvement to visibility at Michigan's

[5] North American Industry Classification System (NAICS) U.S. Census Bureau

Class 1 Areas – compared to all other feasible control measure options that could be applied to the non-EGU source categories.

Through this SIP supplement, EGLE is incorporating the retirements of 31 EGUs from 13 different Michigan power plants (*see* Table 10), which have occurred between 2018 and 2024, into its LTS as on-the-books controls. A Retired Unit Exemption Form filed with the USEPA, certifying the retirement by the owner/operator, has been attached for each unit that EGLE is adopting into the LTS (*See* Appendix 33).

For on-the-way controls, EGLE is also incorporating the Federal Consent Decree for DTE – Belle River, Units 1 and 2, which requires DTE to “retrofit, refuel, or repower” Belle River by December 31, 2030 (*See* Appendix 8).

Table 31: Elements of Michigan's Long-term Strategy for the Second Implementation Period

MICHIGAN CONTROLS

On-the-Books Controls

VOC RACT/Control Techniques Guidelines under Michigan Air Pollution Control Rules

Retirements

Facility Name	Facility Unit ID	Retirement Date
ST. CLAIR / BELLE RIVER POWER PLANT	St. Clair Boiler 7	5/31/2022
	St. Clair Boiler 3	5/31/2022
	St. Clair Boiler 2	5/31/2022
	St. Clair Boiler 1	3/27/2019
	St. Clair Boiler 6	5/31/2022
	St. Clair Boiler 4	11/13/2017
WISCONSIN ELECTRIC POWER COMPANY, Marquette – Presque Isle	Boiler 9	4/8/2019
	Boiler 7	4/8/2019
	Boiler 8	4/8/2019
	Boiler 6	4/8/2019
	Boiler 5	4/8/2019
DTE - Electric Company TRENTON CHANNEL	Boiler 9A	7/8/2022
DTE - Electric Company RIVER ROUGE	Unit 1	6/7/2021
	Unit 3	6/1/2021
Lansing Board of Water & Light (LBWL), Erickson Station	Unit 1	11/28/2022
LBWL, Eckert Station	Unit 1	12/31/2020
	Unit 3	12/31/2020
	Unit 4	5/31/2021
	Unit 5	12/31/2020
	Unit 6	12/31/2020
Consumers Energy – D.E. Karn Facility	Karn 1	6/1/2023
	Karn 2	6/1/2023
MARQUETTE BOARD OF LIGHT & POWER - Shiras	Boiler 3	4/29/2019
Michigan Hub Plant	Unit 1	9/30/2017
DTE – Pontiac North LLC	EUBHB9	1/10/2017
Graphic Packing International, Inc. - Kalamazoo	Unit BLR08	10/07/2024
J B Sims	Unit 3	6/1/2020
James De Young	Unit 5	6/1/2017
Consumers Energy - Thetford	Unit 2	6/1/2019
	Unit 3	4/1/2018
	Unit 4	6/1/2019

On-the-Way Control

DTE – Belle River, Units 1 and 2:
Federal Consent Decree requiring DTE to "retrofit, refuel, or repower" Belle River by December 31, 2030. *See* United States v. DTE Energy, Case No. 2:10-cv-13101-BAF-RSW (E.D. Mich)., Consent Decree filed May 14, 2020. (*See* Appendix 8).
https://www.justice.gov/enrd/consent-decree/file/1276421/download)

NATIONAL CONTROLS
On-the-Books Controls
Revised CSAPR Update (40 CFR 97, Subpart GGGGG)
NESHAP for Reciprocating Internal Combustion Engines
Federal Oil and Natural Gas Industry Standards
NESHAPs for Industrial, Commercial, and Institutional Area Source Boilers, Major Source Boilers (40 CFR 63) (Boiler MACT)
New Source Performance Standards (NSPS) for Commercial and Industrial Solid Waste Incinerators (40 CFR 60 Subpart CCCC, 40 CFR 60 Subpart DDDD)
NSPS for New Residential Wood Heaters (40 CFR 60 Subpart AAA)
SO_2 Data Requirements Rule (40 CFR 51)
Control of Hazardous Air Pollutants from Mobile Sources (also known as the Federal Mobile Source Air Toxics Rules, MSAT2)
Federal Onroad Mobile Source Regulations: - Passenger vehicles, SUVs, and light duty trucks (40 CFR 85, and 86) - Light-duty trucks and medium duty passenger vehicles (40 CFR 86) - Heavy-duty highway compression engines (40 CFR 86) - Heavy-duty spark ignition engines (40 CFR 86) - Motorcycles (40 CFR 86) - Mobile Source Air Toxics (40 CFR 59, 80, 85, and 86) - Light-duty vehicle corporate average fuel economy standards
Federal Nonroad Mobile Source Regulations: - Aircraft (40 CFR 87 and 1068) - Compression Ignition (40 CFR 89 and 1039) - Large Spark Ignition (40 CFR 1048) - Locomotive Engines (40 CFR 1033) - Marine Compression Ignition (40 CFR 1042) - Marine Spark Ignition (40 CFR 1045) - Recreational Vehicle (40 CFR 1051) - Small Spark Ignition Engine

6. Step 6: REASONABLE PROGRESS GOALS FOR 2028 AS ESTABLISHED THROUGH REGIONAL SCALE MODELING OF THE LONG-TERM STRATEGY

Determine the visibility conditions in 2028 that will result from implementation of the LTS and other enforceable measures to set the RPGs for 2028. Typically, a state will do this through regional scale modeling, although the Regional Haze Rule does not explicitly require regional scale modeling. See 40 CFR 51 Submittal.*308(f)(3).*

As provided for in Michigan's 2021 Regional Haze SIP Submittal, EGLE's reasonable progress goals were arrived at by implementing the various controls accounted for in the USEPA inventory, which LADCO modeled, providing the 2028 projected visibility levels at the Seney and

Isle Royale Class I areas in Michigan. LADCO's modeling process is described above under Step 2: Determination of Affected Class I Areas in Other States.

The values included in Tables 1 and 2 and Figures 2 and 3 of Michigan's 2021 Regional Haze SIP Submittal were based on LADCO's modeling for 2028 using a 2011 base year. Reflecting LADCO's more recent modeling for the 2028 projections with 2016 base year, updated tables and figures appear below to depict EGLE's 2028 reasonable progress goals for Isle Royale and Seney under the projected 2028 deciviews (dv) on the 20 percent most impaired and clearest days. For Isle Royale, the 2028 reasonable progress goals were 5.23 dv on the 20 percent clearest days, which is 0.07 dv below the observed visibility impairment in 2014 – 2018, and 14.83 dv on the 20 percent most impaired days, which is 0.71 dv less than the observed visibility impairment in 2014 – 2018 and 1.02 dv below the glidepath. For Seney, the 2028 reasonable progress goals were 5.17 dv on the 20 percent clearest days, which is 0.10 dv less than the observed visibility impairment in 2014 – 2018, and 16.67 dv on the 20 percent most impaired days, which is 0.90 dv less than the observed visibility impairment in 2014 – 2018 and 1.92 dv below the glidepath.

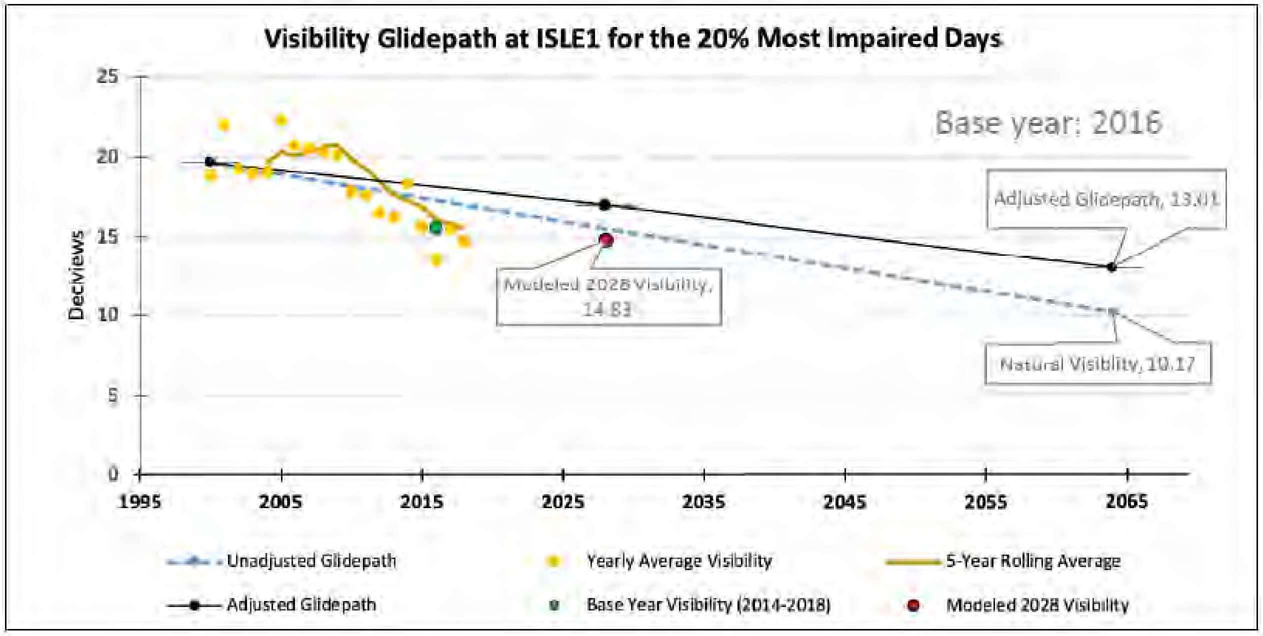
Table 32: Natural Conditions, 2000 – 2004 Baseline Visibility, Observed 2014 – 2018 Visibility, 2028 Projected Visibility, and 2028 Unadjusted Glidepath Value on the 20% Most Impaired Days at Isle Royale and Seney Class I Areas

IMPROVE Site ID	Natural Conditions 20% Most Impaired Days (dv)	Observed 2000-2004 Baseline 20% Most Impaired Days (dv)	Observed 2014-2018 20% Most Impaired Days(dv)	Projected 2028 20% Most Impaired Days (dv) (A)	2028 Unadjusted Glidepath (dv) (B)	2028 Impairment Relative to Unadjusted Glidepath (dv) (A-B)
ISLE1, Isle Royale	10.17	19.63	15.54	14.83	15.85	-1.02
SENE1, Seney	11.11	23.58	17.57	16.67	18.59	-1.92

Table 33: Natural Conditions, 2000 – 2004 Baseline Visibility, Observed 2014 – 2018 Visibility, 2028 Projected Visibility on the 20% Clearest Days at Isle Royale and Seney Class I Areas

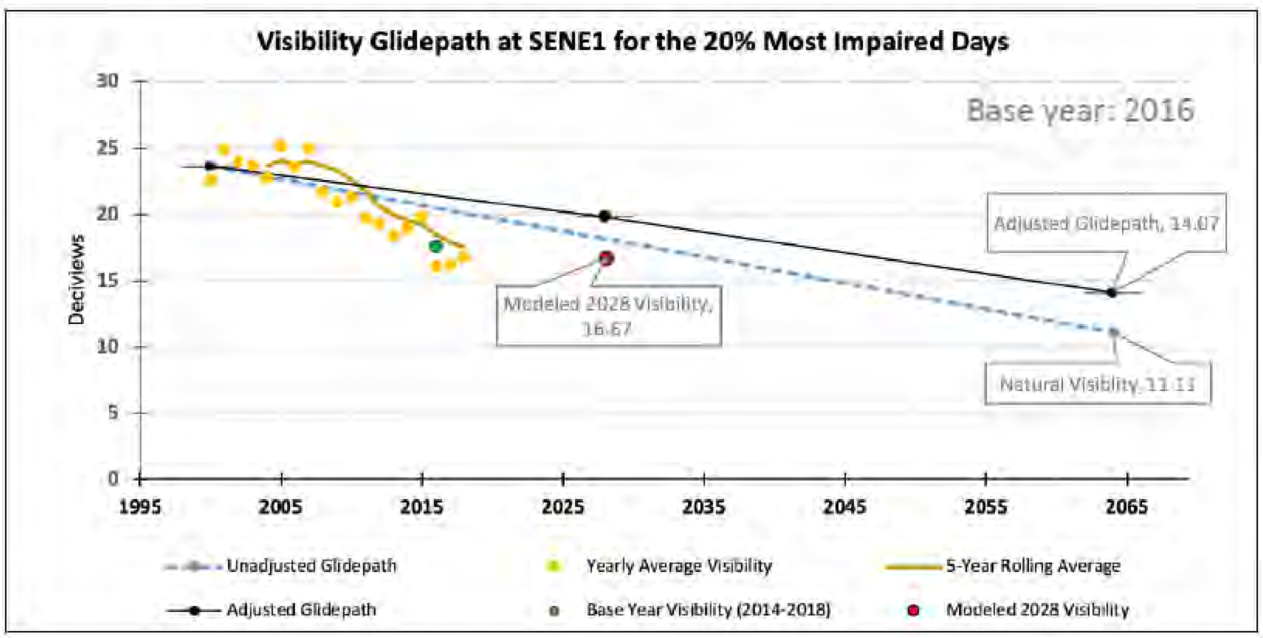
IMPROVE Site ID	Natural Conditions 20% Clearest Days (dv)	Observed 2000-2004 Baseline 20% Clearest Days (dv)	Observed 2014-2018 20% Clearest Days(dv)	Projected 2028 20% Clearest Days (dv) (A)
ISLE1, Isle Royale	3.72	6.77	5.30	5.23
SENE1, Seney	3.74	7.14	5.27	5.17

Figure 20: Visibility Glidepath and 2028 Modeled Visibility at Isle Royale for the 20% Most Impaired Days



Source: LADCO's 2021 Technical Support Document, Figure 7-2

Figure 21: Visibility Glidepath and 2028 Modeled Visibility at Seney for the 20% Most Impaired Days



Source: LADCO's 2021 Technical Support Document, Figure 7-3

7. Step 7: PROGRESS, DEGRADATION, AND URP GLIDEPATH CHECKS

7.1 Checking for improvement in visibility on the 20 percent most impaired days

Demonstrate that there will be an improvement on the 20 percent most anthropogenically impaired days in 2028 at the in-state Class I area, compared to 2000-2004 conditions. See 40 CFR 51.308(f)(3).

This requirement is addressed in Michigan's 2021 Regional Haze SIP submittal on page 25 (*See* Appendix 1).

7.2 Checking for no visibility degradation on the 20 percent clearest days

Demonstrate that there will be no degradation on the 20 percent clearest days in 2028 at the in-state Class I area, compared to 2000-2004 conditions. See 40 CFR 51.308(f)(3).

This requirement is addressed in Michigan's 2021 Regional Haze SIP submittal on page 25 (*See* Appendix 1).

7.3 URP glidepath check

Determine the URP that would achieve natural conditions at the in-state Class I area in 2064. The URP may be adjusted for international anthropogenic impacts and certain wildland prescribed fires subject to USEPA approval as part of USEPA's action on the SIP submission. 40 CFR 51.308(f)(1).

This requirement is addressed in Michigan's 2021 Regional Haze SIP submittal on page 26 (*See* Appendix 1).

7.4 Calculation of the Number of Years it would take to Attain Natural Visibility Conditions

Compare the 2028 RPG for the 20 percent most anthropogenically impaired days to the 2028 point on the URP glidepath for the in-state Class I area. If the RPG is above the URP glidepath, demonstrate that there are no additional emission reduction measures for anthropogenic sources or groups of sources in the state that may reasonably be anticipated to contribute to visibility impairment in the Class I area that would be reasonable to include in the LTS. If the RPG is above the URP glidepath, also provide the number of years needed to reach natural conditions. See 40 CFR 51.308(f)(3)(ii)(A).

This requirement is addressed in Michigan's 2021 Regional Haze SIP submittal on page 26 (See Appendix 1).

8. Step 8: ADDITIONAL REQUIREMENTS FOR REGIONAL HAZE SIPs

8.1 Reasonably Attributable Visibility Impairment

Reasonably Attributable Visibility Impairment (RAVI) is defined as visibility impairment that is caused by the emission of air pollutants from one or a small number of sources. In 2017, the USEPA updated and simplified the provisions for RAVI and extended it to all states, not just those with Class I areas. 40 CFR 51.302 provides:

> "The affected Federal Land Manager may certify, at any time, that there exists reasonably attributable visibility impairment in any mandatory Class I Federal area and identify which single source or small number of sources is responsible for such impairment. The affected Federal Land Manager will provide the certification to the State in which the impairment occurs and the State(s) in which the source(s) is located."
> 40 CFR 51.302

Michigan does not have any sources for which an FLM has provided a RAVI certification.

8.2 Monitoring Strategy and Other Elements

EGLE's monitoring strategy and other elements were addressed in Michigan's 2021 Regional Haze SIP submittal under Section H.3 on page 29 (*See* Appendix 1).

8.3 Five-Year Progress Report for Second Half of First Planning Period

The 1999 Regional Haze Rule required each state to submit progress reports, in the form of SIP revisions, every 5 years after the date of the state's initial SIP submission. *See* 40 CFR 51.308(g). The Regional Haze first implementation period covered the period of 2007 – 2018. Michigan submitted its SIP revision for the first implementation on November 5, 2010, and it was partially approved and partially disapproved on November 26, 2012. *See* 77 FR 71533, December 3, 2012, https://www.govinfo.gov/content/pkg/FR-2012-12-03/pdf/2012-29014.pdf. The USEPA then promulgated a FIP that imposed NO_X and SO_2 limits mandating BART for St. Marys Cement – Charlevoix, controls for SO_2 and NO_X for the Lafarge Midwest – Alpena Plant, and NO_X limits mandating BART for Boilers 8 and 9 at Escanaba Paper (now Billerud – Escanaba LLC). Michigan's BART determination for Tilden Mining taconite plant was addressed in different actions.

Michigan's Regional Haze mid-period progress report for the first half of the first implementation period was submitted on January 12, 2016, and was approved as a SIP revision on May 16, 2018. *See* 83 FR 25375, June 1, 2018, https://www.govinfo.gov/content/pkg/FR-2018-06-01/pdf/2018-11566.pdf.

For the second half of the first implementation period, progress reports are to be submitted as part of the SIP revision for the second implementation period. The 2019 Regional Haze Guidance recommends that the progress report elements cover a time period approximately from the first full year that was not in the previous progress report through a year that is as close as possible to the submission date of the SIP revision. For Michigan, this means that the relevant time period to address for each of the elements of 40 CFR 51.308(g)(1)-(5) is roughly 2015 through 2019. The specific elements of 40 CFR 51.308(g)(1)-(5) are discussed in more detail below.

8.3.1 Status of Control Strategies

40 CFR 51.308(g)(1) requires a description of the status of emission reduction measures:

> *A description of the status of implementation of all measures included in the implementation plan for achieving reasonable progress goals for mandatory Class I Federal areas both within and outside the State.*

Five non-EGU sources in Michigan were identified in the 2010 Regional Haze SIP submittal as being subject to BART. These sources are evaluated below in terms of Haze SIP control measures/limits and status relative to compliance deadlines. This part also describes how three of the five Michigan BART sources are now required to apply additional or more stringent controls beyond those required in the Michigan BART determinations due to USEPA disapprovals of the Michigan BART determinations and issuance of FIPs.

8.3.1.1 Holcim (US), Inc. DBA Lafarge Alpena Plant (referenced in Michigan's 2010 Regional Haze SIP Submittal as Lafarge Midwest, Inc. — Alpena Plant)

A Federal Consent Decree between Lafarge Midwest, Inc., the United States, the State of Michigan and other states and jurisdictions (USA, USEPA, Michigan, et al. v. Lafarge; U.S. District Court Civil Action No. 3:10-cv-00044-JPG-CJP) was entered March 18, 2010, requiring NO_X and SO_2 control for the Alpena plant and other Lafarge plants (*See* Appendix 17) A copy of the Consent Decree is available at: https://www.epa.gov/sites/default/files/documents/lafarge-cd.pdf.

The Consent Decree allowed Lafarge to apply NO_X and SO_2 control measures or to retire or replace any of their five kilns according to a specified schedule to achieve specified facility-wide tpy limits. The control program also set demonstration-phase facility-wide, 12-month rolling limits of 4.89 pounds NO_X per ton of clinker and 3.68 pounds SO_2 per ton of clinker for a period during which individual limits were also to be set for each kiln based on emission testing. These Consent Decree requirements had previously been accepted as BART in the 2010 Regional Haze SIP submittal.

Lafarge opted to install SNCR NO_x control on each kiln, along with DAA for SO_2 control on Kilns 19, 20, 21, and wet FGD SO_2 control on Kilns 22 and 23. The limits and other requirements of the Consent Decree and the selected SO_2 and NO_X control systems were incorporated in PTI No. 95-10B (*copy attached as* Appendix 18), issued on September 13, 2013.

The interim facility-wide, 12-month rolling limits of the Consent Decree are listed below. Annual actual facility-wide emission rates for 2020 (3,778 tpy NO_X and 1,681 tpy SO_2) were well below the Consent Decree 2011 interim 12-month rolling limits.

Consent Decree Deadlines/Limits – USA, USEPA, Michigan, et al. v. Lafarge; U.S. District Court Civil Action No. 3:10-cv-00044-JPG-CJP.

NO_X

- Interim Limit (facility-wide 12-month rolling): 8,650 tons by January 1, 2011
- Install SNCR Control on 3 KG5 Kilns by December 1, 2011
- Install SNCR Control on 2 KG6 Kilns by January 1, 2012.

SO_2

- Interim Limit (facility-wide 12-month rolling): 13,100 tons by January 1, 2011
- Install DAA Control on 3 KG5 Kilns by March 1, 2014
- Install Wet FGD on 2 KG6 Kilns by March 1, 2014.

Compliance Status: Current status as of August 13, 2020, listed in the Michigan Air Compliance and Enforcement System (MACES), indicates compliance with applicable permits, which include the Consent Decree requirements, and Michigan rules. Also, no current enforcement action was found in MACES.

8.3.1.2 Billerud Escanaba LLC

The 2010 Regional Haze SIP submittal indicated that EGLE had accepted Billerud Escanaba LLC's existing PM, NO_X, and SO_2 emission limits as representing BART for their subject equipment. The USEPA later issued a final rule effective on January 2, 2013, disapproving the portion of Michigan's Regional Haze SIP that applied to the BART determination for the company's Boilers 8 and 9 (77 FR 71533, December 3, 2012). The final rule also included a FIP for the company's Boilers 8 and 9 that imposed NO_X BART limits.

The Federal Register publication of the USEPA disapproval action and the FIP can be accessed at: https://www.federalregister.gov/documents/2012/12/03/2012-29014/approval-and-promulgation-of-air-quality-implementation-plans-michigan-regional-haze-state. The USEPA noted in their final rulemaking that Billerud Escanaba LLC had already implemented improvements in combustion control for its boilers and that the limits in the FIP required that the current levels of NO_X control be maintained.

The Boiler 8 NO_X limit was changed by the USEPA to a fixed, rolling 30-day average limit of 0.35 lb. of NO_X per MMBtu, rather than a weighted average of separate limits for oil firing and gas firing. A continuous emission monitor (CEM) system was the required means of compliance determination for Boiler 8. The Boiler 9 NO_X limit was set by the FIP at 0.27 lb. per MMBtu with compliance determination by means of emission testing.

Compliance Status: The most recent inspection that addressed Boilers 8 and 9 was completed on December 11, 2019, through which EGLE's AQD determined Billerud Escanaba LLC to be in compliance with the NO_x FIP limits adopted in PTI No. 127-11D (*copy attached as* Appendix 26), as well as the other applicable Michigan Air Pollution Control Rules.

8.3.1.3 St. Marys Cement – Charlevoix Plant

Michigan's 2010 Regional Haze SIP indicated that EGLE had accepted the St. Marys Cement – Charlevoix Plant existing permitted PM, NO_X, and SO_2 emission limits as representing BART for their subject equipment. The USEPA later issued a final rule effective on January 2, 2013, disapproving the portion of Michigan's Regional Haze SIP that applied to the NO_X and SO_2 BART determination for the cement kiln and associated equipment at St. Marys Cement (77 FR 71533, December 3, 2012). The final rule also included a FIP for this equipment that imposed NO_X and SO_2 BART limits. The Federal Register publication of the USEPA disapproval action and FIP can be accessed at: Federal Register: Approval and Promulgation of Air Quality Implementation Plans; Michigan; Regional Haze State Implementation Plan; Federal Implementation Plan for Regional Haze

The USEPA noted in their final rulemaking, that their BART determination for the facility includes operation of SNCR and a 50 percent reduction in NO_X emissions. The following NO_X emission limits were set in the FIP effective January 1, 2017, along with testing, monitoring, reporting, and recordkeeping requirements:

- 2.80 lbs. NO_X per ton of clinker (30-day rolling average as NO_2);
- 2.40 lbs. NO_X per ton of clinker (12-month average as NO_2); and
- 7.50 lbs. SO_2 per ton of clinker (12-month average).

The USEPA also concluded in the rulemaking that add-on SO_2 control was not warranted as BART set an SO_2 limit of 7.5 lbs. per ton of clinker.

These NO_X and SO_2 BART limits have been federally enforceable through St. Marys Cement – Charlevoix Plant's most recently approved ROP since coming into effect on August 20, 2014 (MI-ROP-B1559-2014) (*copy attached as* Appendix 27).

MI-ROP-B1559-2014 includes a condition that specifies the permittee shall comply with all applicable requirements of the Regional Haze Regulations requiring BART, as specified through 40 CFR 52.1183(h), effective January 1, 2017.

Compliance Status: Through a recent inspection on August 18, 2020, St. Marys Cement - Charlevoix Plant was determined to be in compliance with the applicable NO_X and SO_2 BART conditions under MI-ROP-B1559-2014. No current enforcement action was found in MACES.

8.3.1.4 Smurfit-Stone Container Corporation

Michigan's 2010 Regional Haze SIP indicated that the Smurfit-Stone Container Corporation plant had been shut down since February 2010. The company was listed as American Iron & Metal (SRN A5754) in MAERS as of 2004. No emissions were recorded in MAERS after 2010 and no active permits for the facility were found in the Michigan records of PTIs and ROPs. An inspection on August 27, 2010, indicates the mill had been closed since Autumn 2009. The Smurfit-Stone Ontonagon Mill was sold to Rock-Tenn Company effective May 27, 2011. The name of the new company will be RockTenn CP LLC, per a note in MACES filed by the EGLE District staff. No new air permits were found in the Michigan permit system for the new owner.

As expected, there have been no reported emissions since the shutdown reported for late 2009 or early 2010.

8.3.1.5 Tilden Mining Company LC

Michigan's 2010 Regional Haze SIP submittal indicated that EGLE had accepted the Tilden Mining Company LC existing permitted PM emission limits based on the taconite Maximum Achievable Control Technology (MACT) as representing BART for the indurating furnace/grate-kiln (EU KILN 1), EU PRIMARY CRUSHER, EU COOLER 1, EU DRYER 1, EU BOILER 1, and EU BOILER 2. Michigan's 2010 Regional Haze SIP submittal also accepted the Tilden Mining Company LC cost analysis showing that all technically feasible SO_2 control measures evaluated as BART were not cost-effective. Finally, Michigan's SIP submittal accepted a Tilden Mining Company LC proposal to set a BART NO_X limit for EU KILN 1 before December 31, 2012, based on "good combustion practices" and emission testing.

The USEPA subsequently issued a final rule effective on March 8, 2013, that specified a FIP for certain equipment that imposed NO_X limits for EU KILN 1 (78 FR 8706, February 6, 2013). The Federal Register publication of the USEPA disapproval action and FIP can be accessed at: https://www.federalregister.gov/documents/2013/02/06/2013-01473/approval-and-promulgation-of-air-quality-implementation-plans-states-of-minnesota-and-michigan.

After subsequent litigation, a settlement was entered in April, 2015. These changes to the limits were included in the proposed FIP Rule that was published in the Federal Register on October 22, 2015 (80 FR 64160, October 22, 2015). The Federal Register publication can be accessed at: https://www.govinfo.gov/content/pkg/FR-2015-10-22/pdf/2015-25023.pdf.

On June 8th, 2016, Cliffs Natural Resources, Inc. (owner of Tilden Mining Company LC) petitioned the United States Court of Appeals for review of the final rule ("Air Plan Approval; Minnesota and Michigan; Revision to 2013 Taconite Federal Implementation Plan Establishing BART for Taconite Plants") promulgated by the USEPA and published in the Federal Register on April 12, 2016 (81 FR21672, April 12, 2016). The Federal Register publication can be accessed at: https://www.govinfo.gov/content/pkg/FR-2016-04-12/pdf/2016-07818.pdf. The petition for review was consolidated in the United States Court of Appeals for the Eighth Circuit under lead Case No. 16-2643.

On April 23, 2024, the USEPA published a proposed settlement agreement in Cleveland-Cliffs, Inc. v. Environmental Protection Agency, Case No. 16-2643, which was published in the Federal Register (89 FR 30360), https://www.govinfo.gov/content/pkg/FR-2024-04-23/pdf/2024-08612.pdf (*See* Appendices 13 and 14). If finalized, the proposed settlement agreement would set forth revised NO_X BART limits for EU Kiln 1 in a FIP that would be incorporated into the company's ROP at the state level.

Compliance Status: Although the alternative NO_X and SO_2 BART limits established through the 2015 FIP have not yet come into effect, Tilden Mining Company LC was determined to be in compliance with PTI No. 148-12A (*copy attached as* Appendix 28) and ROP MI-ROP-B4885-2017b *(copy attached as Appendix 29)* through the most recent onsite inspection conducted on August 22, 2019. No current enforcement action was found in MACES.

8.3.2 Emissions Reductions from Regional Haze SIP Strategies

40 CFR 51.308(g)(2) requires a summary of the emissions reductions from regional haze SIP strategies:

> *A summary of the emissions reductions achieved throughout the State through implementation of the measures described in [40 CFR 51.308(g)(1)].*

As in Michigan's 2021 Regional Haze SIP submittal, EGLE continues to believe that SO_2 and NO_X emissions are the most important contributors to haze formation that impact the Class I areas at Isle Royale National Park and Seney Wilderness Area. As illustrated in Figure 5, SO_2 and NO_X emissions lead to the formation of the particulate species of sulfate and nitrate that make up a significant portion of the contribution to visibility impairment at these Class I areas. Accordingly, the following evaluations of emission reductions from SIP and non-SIP LTS control measures and programs have been limited to include only SO_2 and NO_X.

This part of the Progress Report addresses the facility-wide emission reductions from the five first planning period BART sources over the 2015 – 2019 period resulting from the Regional

Haze SIP control measures based on actual emission information and provides a comparison with the emissions from the actual facility-wide emissions from the evaluation done for the 2010 – 2014 period. This type of evaluation is necessary to show the emissions reductions that have occurred since the majority of the compliance deadlines have been reached for the BART FIP limits from the first planning period (except for Tilden Mining Company LC). In the 2016 Progress Report, emissions reductions that were demonstrated for the five first planning period BART sources were not entirely reflective of the BART limits due to the fact that a few of the sources' control measure implementation deadlines had not yet been reached.

8.3.2.1 Holcim (US), Inc. DBA Lafarge Alpena Plant

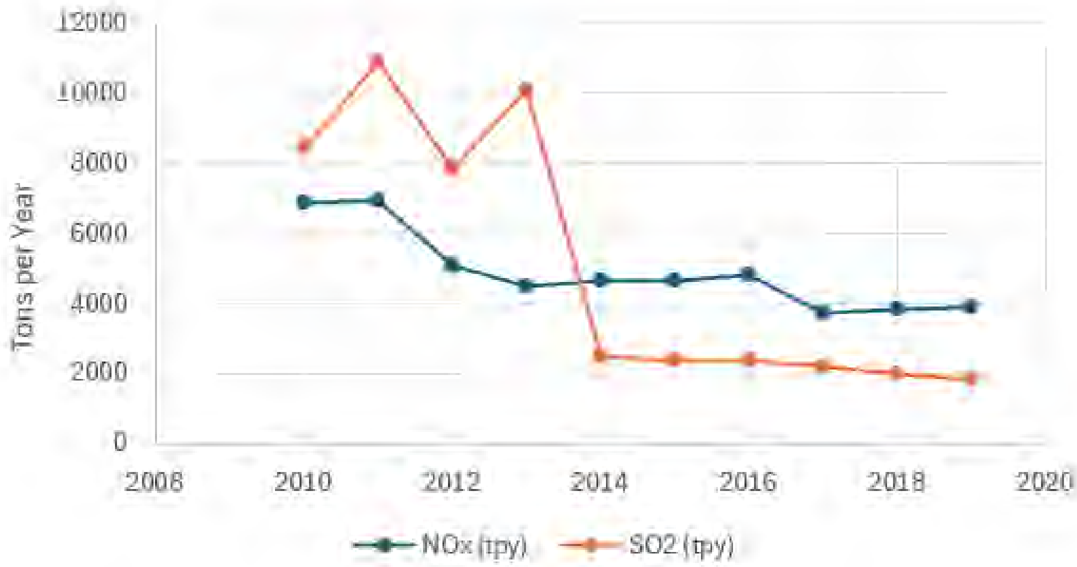
The interim, facility-wide 12-month rolling limits of the federal/state Consent Decree (Consent Decree Limits – USA, USEPA, Michigan, et al. v. Lafarge; U.S. District Court Civil Action No. 3:10-cv-00044-JPG-CJP) are listed below:

- NO_X
  Interim Limit (facility-wide 12-month rolling): 8,650 tons by January 1, 2011.

- SO_2
  Interim Limit (facility-wide 12-month rolling): 13,100 tons by January 1, 2011.

The actual annual facility-wide emissions for 2010 – 2019 appear in Table 34 below. Annual actual facility-wide emission rates for 2011 (6,907 tpy NO_X and 10,905 tpy SO_2) were well below the Consent Decree 2011 interim 12-month rolling limits. Annual actual facility-wide emission rates for 2014 were further reduced for NO_X (to 4,673 tpy); additionally, 2014 actual SO_2 emissions decreased (2,504 tpy) and continued to remain below the Consent Decree interim limit. In 2015, actual facility-wide NO_X and SO_2 emissions were reported to be 4,677 and 2,364 tpy, respectively. While NO_X emissions decreased by approximately 796 tpy between 2015 (4,677 tpy) and 2019 (3,880 tpy), SO_2 emissions were reduced by approximately 506 tpy over the 5-year time period.

Figure 22: Holcim (US), Inc. DBA Lafarge Alpena Plant: Facility-wide Actual Emissions (2010 – 2019)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 34: Holcim (US), Inc. DBA Lafarge Alpena Plant: Facility-wide Actual Emissions (2010 – 2019)

Year	NO_X (tpy)	SO_2 (tpy)
2010	6,894	8,466
2011	6,907	10,905
2012	5,102	7,820
2013	4,504	10,087
2014	4,673	2,504
2015	4,677	2,364
2016	4,834	2,397
2017	3,734	2,232
2018	3,825	1,994
2019	3,880	1,858

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

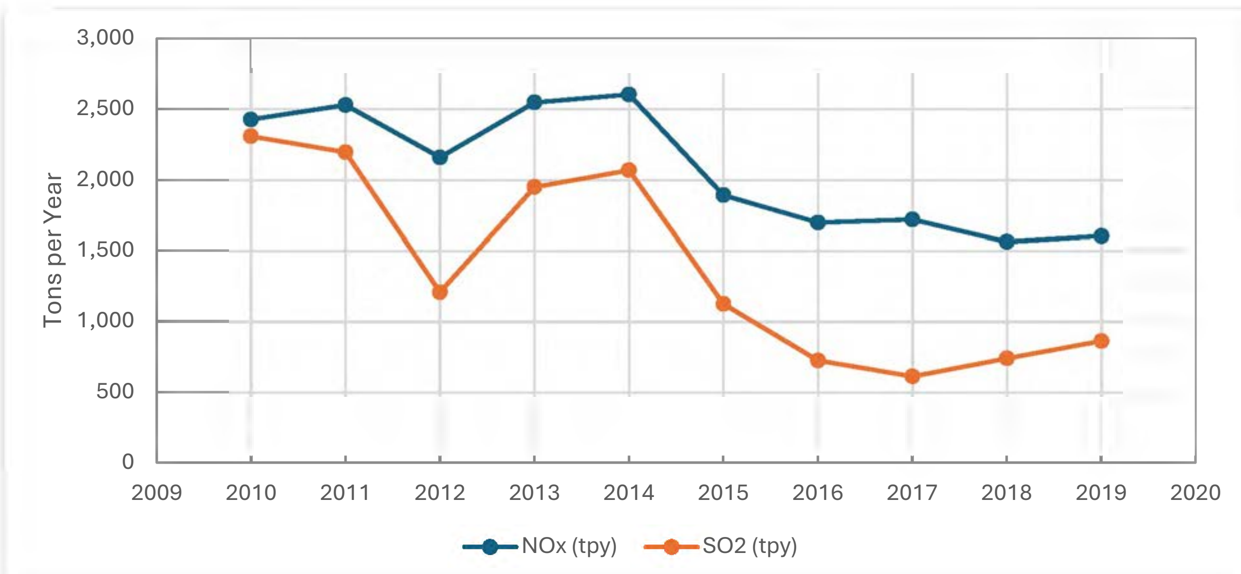
8.3.2.2 Billerud Escanaba LLC

The USEPA issued a final rule effective on January 2, 2013, imposing a FIP for Billerud Escanaba LLC's Boilers 8 and 9 that specified NO_X BART limits (77 FR 71533, December 3, 2012). The Boiler 8 NO_X limit was changed by the USEPA to a fixed, rolling 30-day average limit of 0.35 lb. of NO_X per MMBtu, rather than a weighted average of separate limits for oil-firing and gas-firing. A CEM system was the required means of compliance determination for Boiler 8. The Boiler 9 NO_X limit was set by the FIP at 0.27 lb. per MMBtu with compliance determination by means of emission testing.

Annual actual facility-wide emission rates for 2010 through 2019, for NO_X and SO_2 are provided in Figure 23 and Table 35. The annual emission data demonstrate significant reductions (on average) for NO_X and SO_2 between 2010 and 2019.

Annual actual facility-wide emission rates for 2013 were reported to be 2,549 tpy for NO_X and 1,950 tpy for SO_2. In 2015, actual facility-wide NO_X and SO_2 emissions were reported to be 1,892 and 1,127 tpy, respectively. While SO_2 emissions decreased by 262 tons between 2015 (1,127 tpy) and 2019 (865 tpy), NO_X emissions were similarly reduced by 287 tpy over the 5-year time period.

Figure 23: Billerud Escanaba LLC: Facility-wide Actual Emissions (2010 – 2019)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 35: Billerud Escanaba LLC: Facility-wide Actual Emissions (2010 – 2019)

Year	NO_X (tpy)	SO_2 (tpy)
2010	2,428	2,309
2011	2,530	2,196
2012	2,160	1,210
2013	2,549	1,950
2014	2,605	2,069
2015	1,892	1,127
2016	1,699	727
2017	1,721	614
2018	1,564	742
2019	1,605	865

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

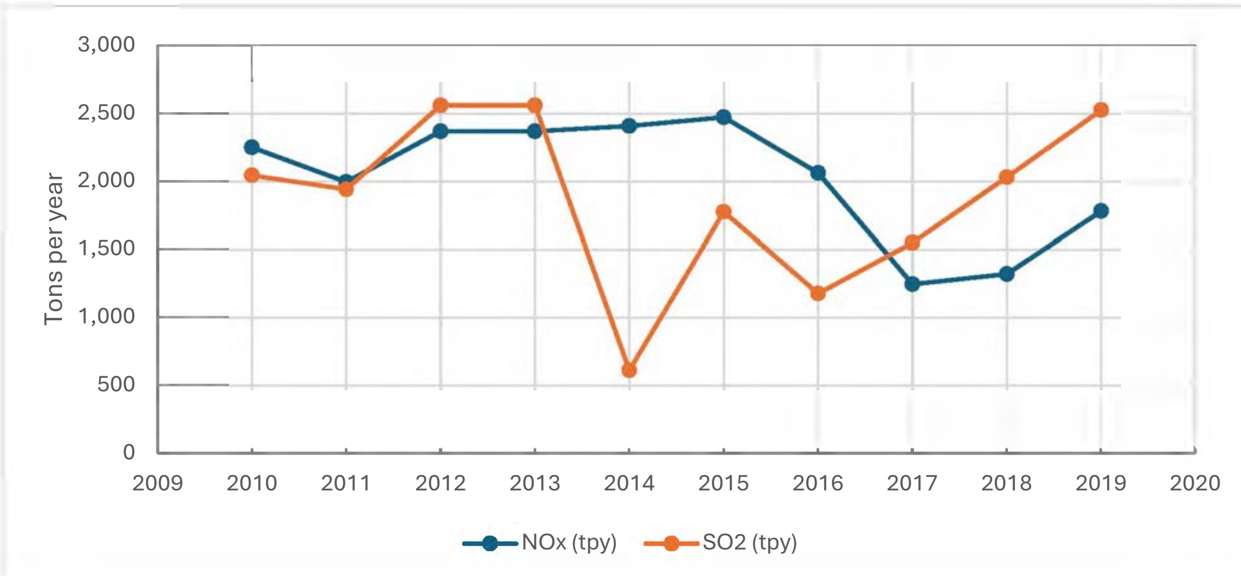
8.3.2.3 St. Marys Cement – Charlevoix Plant

The USEPA imposed a FIP setting BART SO_2 and NO_X limits that became effective on January 1, 2017 (77 FR 71533, December 3, 2012). The ROP was then modified to add a requirement specifying that St. Marys Cement – Charlevoix Plant must comply with applicable BART by the USEPA deadline. Following this, EGLE re-opened the ROP to incorporate the specific FIP BART requirements.

Annual actual facility-wide emission rates for 2010 through 2019 for NO_X and SO_2 are provided in Figure 24 and Table 36.

Annual actual facility-wide emission for 2013 were reported to be 2,369 tpy for NO_X and 2,560 tpy for SO_2. In 2015, actual facility-wide NO_X and SO_2 emissions were reported to be 2,473 and 1,777 tpy, respectively. While SO_2 emissions increased by 748 tons between 2015 (1,777 tons) and 2019 (2,525 tons), NO_X emissions decreased by 691 tons over the 5-year time period.

Figure 24: St. Marys Cement – Charlevoix Plant: Facility-wide Actual Emissions (2010 – 2019)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 36: St. Marys Cement – Charlevoix Plant: Facility-wide Actual Emissions (2010 – 2019)

Year	NO_X (tpy)	SO_2 (tpy)
2010	2,251	2,045
2011	1,996	1,942
2012	2,369	2,560
2013	2,369	2,560
2014	2,408	614
2015	2,473	1,777
2016	2,063	1,179
2017	1,248	1,551
2018	1,322	2,031
2019	1,782	2,525

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

8.3.2.4 Smurfit-Stone Container Corporation

The 2010 Regional Haze SIP indicated that the Smurfit-Stone Container Corporation plant has been shut down since February 2010. No emissions were recorded in MAERS after 2010, and no active permits for the facility were found in the Michigan records of PTIs and ROPs. An inspection on August 27, 2010, indicates the mill had been closed since Autumn 2009.

Smurfit-Stone Container Corporation's annual actual facility-wide emission rates for 2009 through 2010, as well as for 2015 through 2019, for NO_X and SO_2 are provided in Table 37. As expected, there have been no reported emissions since the shutdown reported for late 2009 or early 2010.

Table 37: Smurfit-Stone Container Corporation: Facility-wide Actual Emissions (2009 – 2019)

Year	NO_X (tons/year)	SO_2 (tons/year)
2009	208	1,231
2010	2.23	0.01
2015		
2016		
2017		
2018		
2019		

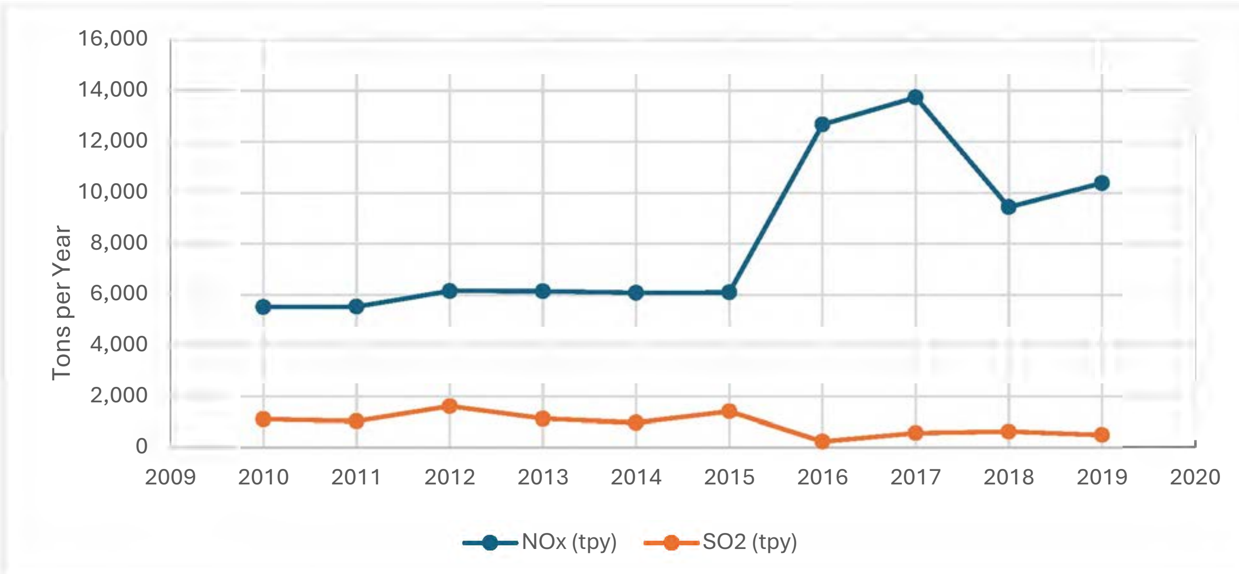
8.3.2.5 Tilden Mining Company LC

Despite the ongoing litigation surrounding the NO_X/SO_2 BART limits established in the 2015 FIP Rule, Tilden Mining Company LC's ROP has been modified to add a condition specifying that the facility must comply with the applicable requirements of 40 CFR Part 52, Approval and Promulgation of Implementation Plans, Subpart X—Michigan, Section 52.1183 Visibility Protection, which would include the newly proposed BART limits for EUKILN1 beginning 30 days after the date of publication in the Federal Register. EGLE would then re-open the ROP and incorporate the FIP BART limits into the ROP in accordance with the renewal schedule.

Annual actual facility-wide emission rates for 2010 through 2019, for NO_X and SO_2 are provided in Figure 25 and Table 38. The annual emission data demonstrates a relatively significant increase (on average) in NO_X emissions facility-wide, while also showing a reduction (on average) in SO_2 emissions between 2010 and 2019).

Annual actual facility-wide emission rates for 2013 were reported to be 6,142 tons for NO_X and 1,132 tons for SO_2. In 2015, actual facility-wide NO_X and SO_2 emissions were reported to be 6,097 and 1,412 tons, respectively. While SO_2 emissions decreased by 911 tons between 2015 (1,412 tons) and 2019 (501 tons), NO_X emissions increased by 4,282 tons over the 5-year time period. In an effort to understand how NO_X and SO_2 emissions have changed since the implementation of NO_X and SO_2 BART limits for this kiln through the FIP, EGLE calculated the difference between the 5-year annual average NO_X and SO_2 emissions rates for the 2015 – 2019 evaluation period and the 5-year annual average NO_X and SO_2 emissions rates for the 2010 – 2014 evaluation period. This comparison showed the relative change in emissions from the 2010 – 2014 period to the 2015 – 2019 period with NO_X emissions higher by 4,582 tpy and SO_2 emissions lower by 501 tpy.

Figure 25: Tilden Mining Company LC: Facility-wide Actual Emissions (2010 – 2019)



Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

Table 38: Tilden Mining Company LC: Facility-wide Actual Emissions (2010 – 2019)

Year	NO_X (tpy)	SO_2 (tpy)
2010	5,520	1,112
2011	5,535	1,036
2012	6,149	1,617
2013	6,142	1,132
2014	6,079	976
2015	6,097	1,412
2016	12,677	245
2017	13,741	575
2018	9,440	636
2019	10,379	501

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

8.3.3 Visibility Progress

40 CFR 51.308(g)(3) requires an assessment of visibility conditions and changes for each Class I area within the state:

> *For each mandatory Class I Federal area within the State, the State must assess the following visibility conditions and changes, with values for most impaired, least impaired and/or clearest days as applicable expressed in terms of 5-year averages of these annual values. The period for calculating current visibility conditions is the most recent 5-year period preceding the required date of the progress report for which data are available as of a date 6 months preceding the required date of the progress report.*
>
> > *(i)(A) …the current visibility conditions for the most impaired and least impaired days.*
> >
> > *(ii)(A) …the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions.*
> >
> > *(iii)(A) …the change in visibility impairment for the most impaired and least impaired days over the period since the period addressed in the most recent plan required under [40 CFR 51.308(f)].*

For the Isle Royale and Seney Class I area sites, EGLE's AQD acquired the following IMPROVE visibility data from the FLM Environmental Database (https://views.cira.colostate.edu/fed/).

Michigan's most impaired days have continued to improve since the 2016 Progress Report update. In 2019, the IMPROVE monitor at Isle Royale National Park (ISLE1) demonstrated a 5-year average light extinction of 14.9 dv, down from 17.3 dv in 2014. Seney National Wildlife Refuge (SENE1) improved from 19.5 dv to 17.1 dv over the same time period.

Clearest days have also improved during this implementation period. Isle Royale's clearest days have reduced average light extinction from 5.5 dv in 2014 to 5.1 dv in 2019. Seney improved from 5.5 dv to 5.1 dv over the same time period.

8.3.4 Emissions Progress

40 CFR 51.308(g)(4) requires an analysis of emissions changes since the last regional haze SIP revision:

> *An analysis tracking the change over the period since the period addressed in the most recent plan required under [40 CFR 51.308(f)] in emissions of pollutants contributing to visibility impairment from all sources and activities within the State. Emissions changes should be identified by type of source or activity. With respect to all sources and activities, the analysis must extend at least through the most recent year for which the state has submitted emission inventory information to the Administrator in compliance with the triennial reporting requirements of [40 CFR Part 51, Subpart A] as of a date 6 months preceding the required date of the progress report. With respect to sources that report directly to a centralized emissions data system operated by the Administrator, the analysis must extend through the most recent year for which the Administrator has provided a State level summary of such reported data or an internet-based tool by which*

the State may obtain such a summary as of a date 6 months preceding the required date of the progress report. The State is not required to back cast previously reported emissions to be consistent with more recent emissions estimation procedures and may draw attention to actual or possible inconsistencies created by changes in estimation procedures.

8.3.4.1. NO_X and SO_2 Statewide Point Source Emissions

Statewide point source emissions for Michigan were determined for both 2014 and 2019 for the progress report element of the second planning period SIP. Actual NO_X and SO_2 emission data for this comparison was derived from MAERS, which was accessed at: EGLE - Michigan Air Emissions Reporting System (MAERS) - Annual Pollutant Totals Query

The 2014 and 2019 actual NO_X and SO_2 data is summarized in Table 39. The data indicates substantial reductions over the 6-year evaluation period for both NO_X (33,442 tons) and SO_2 (111,459 tons), representing a decrease in statewide point source emissions over the 6-year period from 2014 to 2019 of 29 percent for NO_X and 63 percent for SO_2.

Table 39: 2014 vs 2019 Statewide Actual NO_X and SO_2 Emissions for All Michigan Point Sources Statewide

Source Category	2014 NO_X Actual Emissions (tons)	2019 NO_X Actual Emissions (tons)	NO_X Emissions Change: 2014 vs 2019 tons	2014 SO_2 Actual Emissions (tons)	2019 SO_2 Actual Emissions (tons)	SO_2 Emissions Change: 2014 vs 2019 tons
All Michigan Point Sources, Statewide*	113,605	80,163	-33,432	176,704	65,245	-111,459

*Does not include transportation, residential, and small stationary sources.

Source: MAERS Annual Pollutant Totals Query
https://www.egle.state.mi.us/maers/emissions_query.asp

8.3.4.2 NO_X and SO_2 Total Statewide Emissions

2014 and 2019 statewide emissions trends data for NO_X and SO_2 was acquired from the USEPA Air Emissions Inventories Website at: https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data. The emissions data were broken down into 14 emissions source categories that capture point, area, mobile, and event sources.

As expected, and as depicted in Figure 26 and Table 40, total statewide SO_2 emissions decreased by approximately 118,000 tons across the 6-year evaluation period (2014 – 2019), while total statewide NO_X emissions were reduced by approximately 112,000 tons. The most substantial decrease across all emissions source categories is for SO_2 emissions from the Fuel Combustion Electric Utility (EGU) category (103,324 tons) (*as shown in* Table 40). NO_X emissions from Highway Vehicles (*as show in* Table 41) sources also showed a large decrease across the 6-year timespan (68,411 tons). Across the 14 emissions source categories, 5 saw minimal increases in SO_2 emissions between 2014 and 2019, while 4 demonstrated insignificant increases in NO_X emissions.

Table 40: SO_2 Statewide Emissions Trends by Category (2014 and 2019)

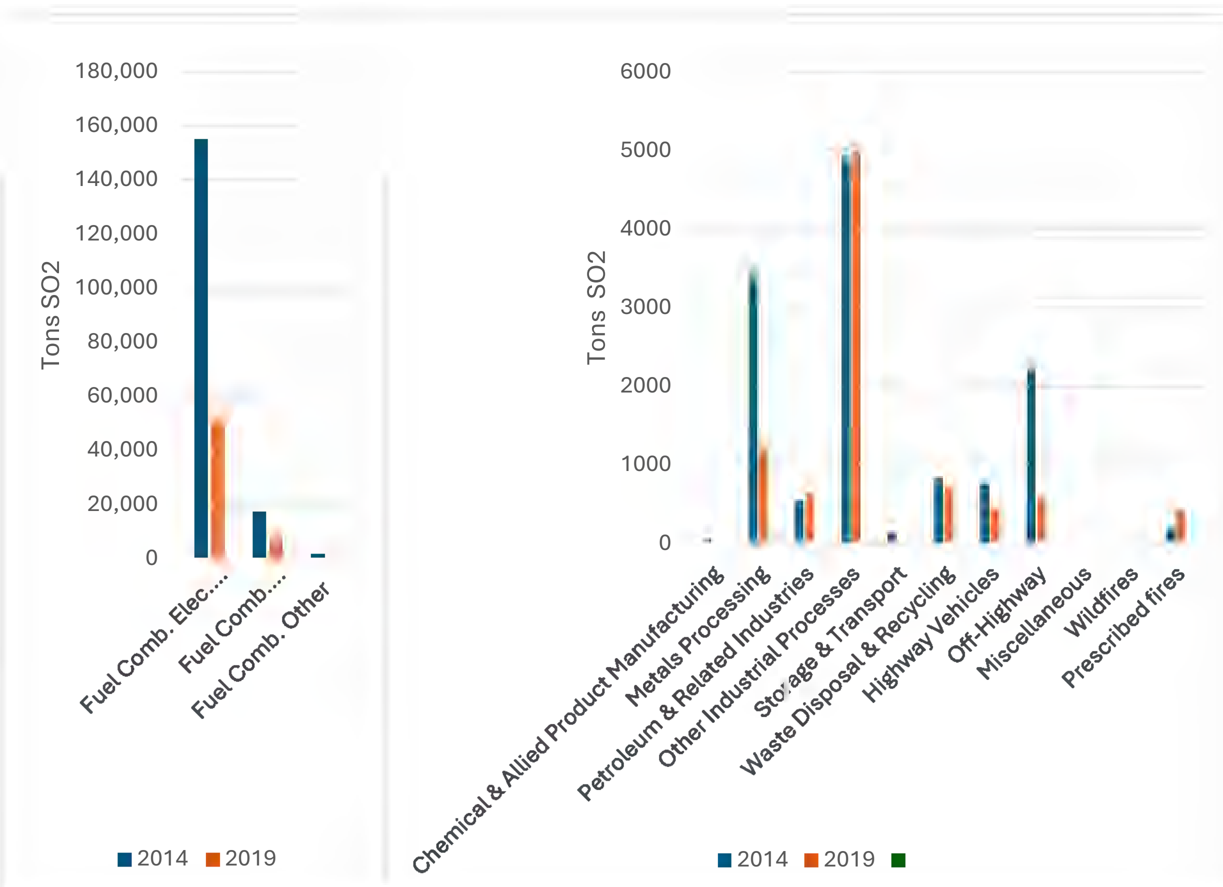
Category	Pollutant	emissions2014 (tons)	emissions2019 (tons)	Change in Emissions (2014-2019) (tons)
Fuel Comb. Elec. Util.	SO_2	155,180	51,856	-103,324
Fuel Comb. Industrial	SO_2	17,323	7,766	-9,557
Fuel Comb. Other	SO_2	1,737	883	-854
Chemical & Allied Product Manufacturing	SO_2	37	10	-27
Metals Processing	SO_2	3,406	1,213	-2,193
Petroleum & Related Industries	SO_2	533	650	117
Other Industrial Processes	SO_2	4,917	4,974	57
Storage & Transport	SO_2	123	0	-123
Waste Disposal & Recycling	SO_2	817	705	-112
Highway Vehicles	SO_2	745	436	-309
Off-Highway	SO_2	2,223	580	-1,643
Miscellaneous	SO_2	6	15	9
Wildfires	SO_2	1	11	10
Prescribed fires	SO_2	196	432	236
Total	SO_2	187,244	69,531	-117,713

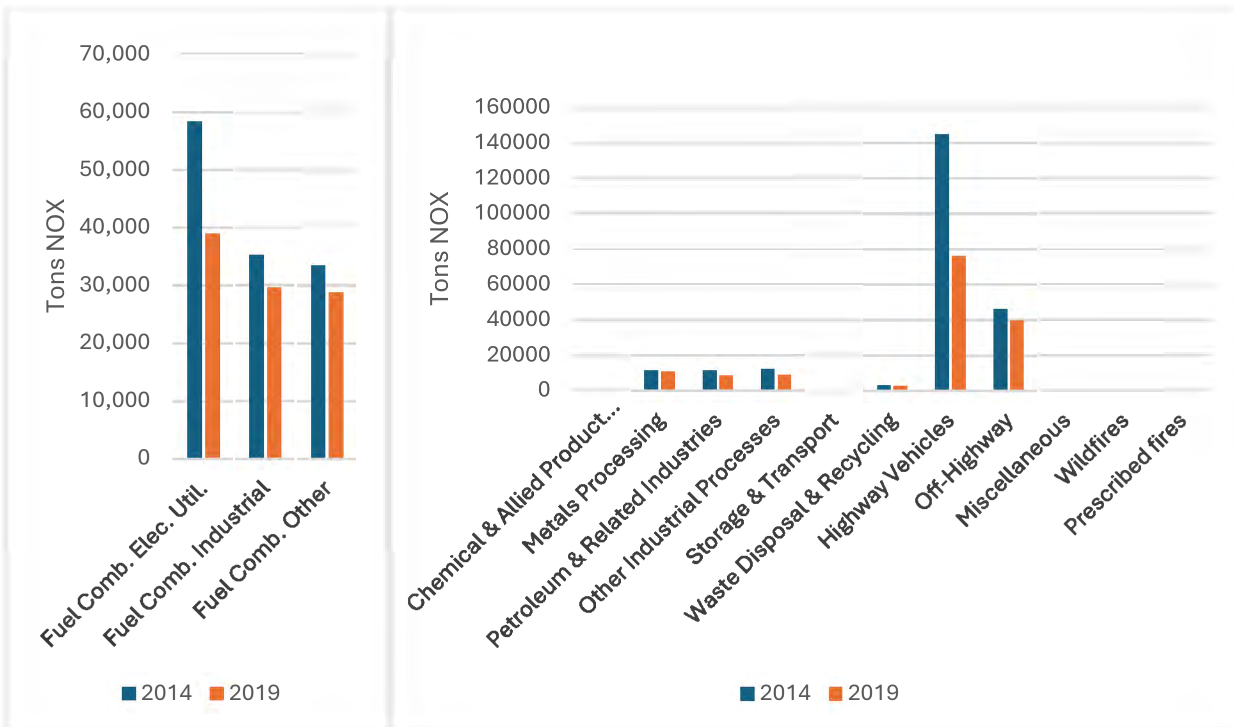
Table 41: NO_X Statewide Emissions Trends by Category (2014 and 2019)

Category	Pollutant	emissions2014 (tons)	emissions2019 (tons)	Change in Emissions (2014-2019) (tons)
Fuel Comb. Elec. Util.	NO_X	58,306	38,911	-19,395
Fuel Comb. Industrial	NO_X	35,227	29,518	-5,709
Fuel Comb. Other	NO_X	33,385	28,741	-4,644
Chemical & Allied Product Manufacturing	NO_X	70	46	-24
Metals Processing	NO_X	11,188	10,660	-528
Petroleum & Related Industries	NO_X	11,480	8,433	-3,047
Other Industrial Processes	NO_X	12,040	8,722	-3,318

Category	Pollutant	emissions2014 (tons)	emissions2019 (tons)	Change in Emissions (2014-2019) (tons)
Storage & Transport	NO_X	12	12	0
Waste Disposal & Recycling	NO_X	3,169	2,518	-651
Highway Vehicles	NO_X	144,675	76,264	-68,411
Off-Highway	NO_X	46,182	39,443	-6,739
Miscellaneous	NO_X	11	62	51
Wildfires	NO_X	1	20	19
Prescribed Fires	NO_X	284	678	394
Total	NO_X	356,030	244,028	-112,002

Figure 26: 2014 vs 2019 Statewide Actual NO_X and SO_2 Emissions by Category





8.3.4.3 Assessment of Changes Impeding Visibility Progress

40 CFR § 51.308(g)(5) requires an assessment of changes impeding visibility progress:

> *An assessment of any significant changes in anthropogenic emissions within or outside the State that have occurred since the period addressed in the most recent plan required under [40 CFR § 51.308(f)] including whether or not these changes in anthropogenic emissions were anticipated in that most recent plan and whether they have limited or impeded progress in reducing pollutant emissions and improving visibility.*

Michigan has not identified, nor does it anticipate any significant changes in either in-state or out-of-state emissions that would impede visibility progress at its Class I areas. Although a number of source categories within Michigan and other bordering states (Indiana, Illinois, etc.) demonstrated increases in NO_X and/or SO_2 emissions between 2014 and 2019 (according to the information published to the USEPA's Air Pollutant Emissions Trends Data Webpage (https://www.epa.gov/air-emissions-inventories/air-pollutant-emissions-trends-data), EGLE does not consider this a significant issue impeding visibility progress for the Michigan Regional Haze SIP given that substantial NO_X and SO_2 reductions have occurred from other anthropogenic sources that vastly outweigh the impacts of these minor NO_X/SO_2 emissions increases within the Midwest region of the United States.

8.4 Consultation and Discussions with Other Parties

8.4.1 FLM Consultation

EGLE facilitated a consultation period with the FLMs from December 19, 2024, to February 14, 2025, to discuss EGLE's draft SIP Supplement, providing at least 60 days before holding a public hearing or announcing a public comment opportunity as required under 40 CFR 51.308(i)(2). Appendix 30 contains the comments received from the FLMs. Appendix 32 contains Michigan's response to all comments received during this process.

8.4.2 Public Comment

After consideration of FLM comments, Michigan provided a comment period and the opportunity for a public hearing on the proposed SIP Supplement for the Regional Haze second implementation period from March 10, 2025 to April 8, 2025. Appendix 31 contains the public notice and comments received during that comment period. Appendix 32 contains Michigan's response to all comments received during this process.

APPENDICES

(Please note: Appendices A – E are contained in Michigan's August 23, 2021 Regional Haze SIP submittal. For reference, Michigan's August 23, 2021 Regional Haze SIP submittal is included in full as Appendix 1 in this SIP Supplement).