MICHIGAN PUBLIC SERVICE COMMISSION

2024 Upper Peninsula Energy Report

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Executive Summary

Governor Gretchen Whitmer signed Public Act 235 (PA 235) into law on November 28, 2023. PA 235 establishes that an electric provider shall achieve a renewable energy credit portfolio of at least 50% in 2030 through 2034 and 60% in 2035 and thereafter. PA 235 also established a clean energy standard whereby electric providers in the state shall achieve a clean energy portfolio of at least 80% by 2035 through 2039 and 100% in 2040 and thereafter. The Legislature recognized the uniqueness of Michigan's Upper Peninsula (UP) and, as part of PA 235, tasked the Michigan Public Service Commission (MPSC) with evaluating the current energy landscape of the UP and potential paths forward for compliance with the law. As part of this evaluation, the Legislature directed the MPSC to consider the unique circumstances involving the natural gas-fired Reciprocating Internal Combustion Engine (RICE) units operated by Upper Michigan Energy Resources Corporation (UMERC).

The UMERC RICE units were built to enable the full retirement of the Presque Isle Power Plant and alleviate expensive system support resource (SSR) charges that were impacting UP customers. At about the same time, the Marquette Board of Light and Power (MBLP) also constructed three RICE units to enable the retirement of Shiras Power Plant. With both coal electric generation facilities retired and the continued operation of several hydroelectric facilities, the UP achieved significant emissions reductions far outpacing reductions in the Lower Peninsula. The UP electric sector has reduced its carbon dioxide (CO_2) emissions by approximately 71% between 2013 and 2022.

This report provides an overview of the energy landscape of the UP as it relates to electric generation, transmission, and load. It reviews the history of the UP's energy system and the unique conditions and challenges facing UP utilities and communities as we move toward a clean energy future. It also examines several clean energy options and how they specifically relate to the UP. Having compiled and reviewed the information necessary to develop this report, the Commission provides the following observations and recommendations:

- The Commission believes it would be helpful to understand whether the UP can accommodate more Energy Waste Reduction (EWR) than what Public Act 229 of 2023 requires. To that end, as part of the implementation of the 2023 energy legislation, a potential study that quantifies the economic/technical/achievable potential of EWR in the UP is underway. Results are expected Q3 of 2025.

- Additional clarity concerning the breadth of technologies that can be considered clean energy systems could help electric providers as they seek to determine the most reasonable and prudent path forward. A clear understanding of the types of technologies that can be considered clean energy systems is necessary to develop a clean energy plan, reducing risk and uncertainty for electric providers. Two possible paths to further define clean energy systems are: 1) for the

Legislature to further define clean energy systems, and 2) for the Commission to embark on a rulemaking process. Tire-derived fuels, renewable natural gas, and direct air capture technologies are not expressly identified as clean energy technologies in the law. If either the Legislature or Commission rules resulted in the inclusion of biomass with TDF as part of the fuel source, such a change should include a demonstration that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation.

- Under PA 235, the limitation on distributed generation resources increased from 1% of a utility's average peak load to 10%. This change is likely to increase interest in opportunities to aggregate distributed generation and other distributed energy resources. At the same time, the issuance of Order 2222 by FERC in September 2020 provides a pathway for aggregated distributed energy resources to participate in wholesale energy markets, potentially providing a cost-effective, distributed approach for customer-owned resources to contribute to maintaining reliability and participating in the energy transition in the UP. In its December 21, 2022 order in Case No. U-21099, the Commission partially lifted the prohibition on the ability of aggregated demand response resources from participating in regional power markets as part of the Commission's ongoing efforts to bolster Michigan's energy capacity. However, the actions taken to date only apply to retail commercial and industrial customers with a minimum enrolled load of 1 megawatt, with the Commission noting that "additional work surrounding customer protections is warranted" before allowing participation by residential and smaller commercial customers. The Legislature should work to enact a statutory framework that provides meaningful consumer protections while providing a pathway for aggregated DERs to participate in the regional wholesale electricity markets, consistent with FERC Order 2222.

- The Legislature should consider expanding the concept of "functional equivalence" to include accelerated economy-wide carbon reduction as a carbon reduction option for power generation by including consideration of carbon reduction in another sector. Considerations of "functional equivalence" should apply to more than just power generation, taking a more holistic view accounting for all sources of carbon emissions. The aim of the MI Healthy Climate Plan is economy-wide emissions reduction, and these efforts could help to offset hard-to-abate emissions in the power sector. In the alternative, the Commission could consider whether the rulemaking authority provided for in PA 235 includes an opportunity to build on the concept of "functional equivalence."

- The Legislature should consider expanding the idea of joint clean energy planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 1,000,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to achieve Michigan's clean energy goals and storage targets in a more economical way. More specifically, this would allow for UP-wide solutions to be considered.

The Commission has worked closely with the Midcontinent Independent System Operator (MISO) and the American Transmission Company (ATC) to perform certain modeling of the UP-transmission system under various conditions to better understand how the clean energy standard may impact the reliability. Due to the extensive modeling necessary, the MISO results will be provided in early 2025.

Acknowledgements

The Commission and Commission Staff would like to thank all those who participated and provided information necessary to complete this report. While conducting this study, the Commission engaged in substantial outreach with organizations and interested persons to gather information and UP perspectives. The Commission Staff engaged in many discussions with a range of UP organizations. Special thanks to those who answered Staff-issued questions and/or provided information to Staff either directly or in the U-21572 docket. UP organizations and representatives who provided insight into our work include: UP investor-owned utilities, municipal utilities, electric cooperatives, and member organizations; elected officials; leaders and staff members from several of the federally recognized Tribes in the UP; the Michigan Department of Environment, Great Lakes, and Energy's Oil, Gas, and Mineral Division; the Michigan Department of Environment, Great Lakes, and Energy's Scrap Tire Program; the Midcontinent Independent System Operator; American Transmission Co.; Invest UP; Superior Watershed Partnership; Cleveland-Cliffs' Tilden Mine; Billerud; L'Anse Warden Power Plant; and Wärtsilä.

Introduction

Governor Gretchen Whitmer signed Public Act 235 of 2023 (PA 235) into law on November 28, 2023. PA 235 establishes that an electric provider shall achieve a renewable energy credit portfolio of at least 50% in 2030 through 2034 and 60% in 2035 and thereafter. PA 235 also established a clean energy standard whereby electric providers in the state shall achieve a clean energy portfolio of at least 80% by 2035 through 2039 and 100% in 2040 and thereafter. In establishing these requirements, the Legislature also recognized the unique history and features of the electricity system in Michigan's Upper Peninsula (UP) and, as part of PA 235, tasked the Michigan Public Service Commission (MPSC) with evaluating the current energy landscape of the UP, including the unique role of the Reciprocating Internal Combustion Engine (RICE) units separately owned and operated by Upper Michigan Energy Resources Corporation (UMERC) and Marquette Board of Light and Power (MBLP), and potential paths forward for compliance with the law. This report provides an overview of the energy landscape of the UP as it relates to electric generation, transmission, and load. It also reviews the history of the UP's energy system and the unique conditions and challenges facing UP utilities and communities as Michigan moves toward a clean energy future.

Background of the UP Electricity System

As large industry developed across the UP, including mining and paper milling, electric generation developed to support their operations. In some cases, this generation also supported the surrounding population. Over time, these industry-owned facilities were sold to utilities resulting in an intertwined electrical system that connects dispersed load pockets that are geographically and electrically distinct. In some instances, the symbiotic nature of the generation facilities and industries that originally built them continued despite changes in the ownership of the facilities and integration into the broader system. The development of distinct and dispersed load centers resulted in many different electric providers. It also resulted in a patchwork electric system with limited linkage between load centers and resources creating an almost islanded system at these specific load centers. Today, the UP remains dominated by industrial load with 60% of the UP's load originating from industrial customers. By comparison, approximately 30% of the Lower Peninsula's load is attributable to industrial customers.

The Presque Isle Power Plant (PIPP) provides an example of a symbiotic relationship described above. PIPP was originally constructed by the Cleveland-Cliffs Iron Company in 1955 to power its mining and processing operations outside of Marquette. PIPP was sold to the Upper Peninsula Power Company (UPPCo) in the early 1980s and later sold to Wisconsin Energy. The facility, however, was critical to supporting the UP's transmission system until it was eventually replaced by the

UMERC RICE units and retired in 2019. Despite ownership of PIPP, and later the UMERC RICE units, no longer resting with Cleveland-Cliffs, the relationship between the company and the utility serving it was critical to the operation and retirement of PIPP and the building of the UMERC RICE units that replaced PIPP.

Michigan's geography also plays a role in the historic development of the UP electric system as the Lower Peninsula and Upper Peninsula developed separately and distinctly from one another. As discussed later in detail, American Transmission Company (ATC) provided a link between the two peninsulas through a high voltage direct current device in 2014. Although this device strengthens the link between the peninsulas, it did not strengthen the broader underlying transmission system of either the Upper or Lower Peninsula specifically. Therefore, the transfer capability, which is the amount of electricity that can move between the peninsulas, is limited on a day-to-day basis. This results in the Upper Peninsula being more closely tied electrically to Wisconsin than the Lower Peninsula. The linkage to Wisconsin has allowed for the flow of energy from resources located there but also has resulted in limited resource development in the Upper Peninsula.

The UP currently houses 9.2 MW of solar power, 68.4 MW of diesel fuel generation, 239.3 MW of natural gas generation, 183.9 MW of hydroelectric generation, 22 MW of biomass fuel generation, 100.8 MW of wind generation, and approximately 180 MW of combined heat and power generation resources that are primarily owned by utility customers and operate behind the meter. All values are nameplate capacity values and therefore do not account for any variation in availability or differences in accredited capacity.

2023 Energy Law and Development of UP Report

On November 28, 2023, Public Acts 229, 231, 233, and 235 were signed into law by Governor Gretchan Whitmer. Among other things, these laws:

- Increase the Energy Waste Reduction (EWR) standard for both electric and natural gas providers. For electric providers, the standard is increased from 1% annual energy waste reduction to 1.5% annual energy waste reduction, with a goal of 2% annual energy savings. For natural gas providers, the standard is increased from .75% annually to .85% annually.
- Allow for "fuel switching" in energy waste reduction programs (i.e., changing a customer's home heating source or appliances from a higher emitting fuel to a lesser emitting fuel), allowing for the electrification of home heating and other appliances.

- Expand the issues for consideration in utility Integrated Resource Plan applications to include affordability, cost effectiveness, labor standards, and promotion of environmental quality and public health.
- Establish a siting process at the Commission for utility scale renewable energy and energy storage facilities under certain conditions.
- Establish a renewable energy standard of 50% by 2030 and 60% by 2035 applicable to all investor-owned utilities, co-operative utilities, and municipally owned utilities. Pursuant to PA 235, "renewable energy" includes wind, solar, existing hydro, existing biomass (but only that which does not use tire derived fuel), and methane digesters with specific feedstocks. With some limited exceptions, renewable energy resources must be physically located in Michigan or within the Regional Transmission Organization (RTO) zone in which the utility is operating.
- Establish a clean energy standard of 80% by 2035 and 100% by 2040. Clean energy is defined in the law to include electricity generating systems that generate electricity or steam without emitting greenhouse gases, including nuclear generation; natural gas generation with 90% effective carbon capture and sequestration for existing natural gas facilities; for new natural gas facilities, only those with carbon capture technology that meets either EPA Best Available Control Technology (BACT) criteria or is 90% effective, whichever is greater; and any other clean energy resources as defined by the Commission. The act also includes within the definition of a clean energy system a carve out for the Midland Cogeneration Venture (MCV) natural gas facility subject to approval by the Commission of a plan that achieves "functional equivalence" with the clean energy standard through reduction of greenhouse gas emissions through carbon capture and sequestration and other available applications, including carbon removal technologies.
- Allow the Commission to grant extensions to the compliance deadlines for both the renewable energy standard and the clean energy standard if the utility can make certain showings related to compliance challenges.
- Expand the minimum size of utility distributed generation programs from 1% to 10% of a utility's average in-state peak load and make other programmatic adjustments.
- Establish a statewide 2,500 MW storage target.

Recognizing the unique characteristics of the UP and the energy system that serves its residents, PA 235 also directs the Commission to conduct a study into the unique energy needs of the UP specifically related to the RICE units owned by UMERC and the impact of mining activities on the UP's energy system. Specifically, PA 235 directs the Commission to provide a written report detailing:

(a) The unique conditions influencing electric generation, transmission, and demand in the Upper Peninsula.

(b) The unique role of the reciprocating internal combustion units placed in service to facilitate the retirement of coal-fired generation located in the Upper Peninsula after the regional transmission organization-imposed system support resource charges.

(c) Changes in electric demand, including changes from mining-related economic development projects, that may influence the utilization of the reciprocating internal combustion units described in subdivision (b).

(d) Options to reduce the carbon intensity of the existing reciprocating internal combustion units described in subdivision (c), with particular focus on how the unique geological conditions within the Upper Peninsula influence the feasibility of deploying clean energy systems.

(e) Any other information the Commission determines may be relevant to the development of strategies to satisfy the clean energy standard for an electric provider whose rates are regulated by the Commission and that owns and operates reciprocating internal combustion engine units in the Upper Peninsula.

On February 8, 2024, the Commission issued an Order in MPSC Case No. U-21572 initiating the required study and directing the Commission's Staff to prepare a report examining the role of the RICE units and transmission reliability with aid from UMERC, ATC, Cleveland-Cliffs, and MISO and to investigate the roles Energy Waste Reduction, Demand Response, generation, and transmission infrastructure play in grid stability and resource adequacy should the RICE units be retired or otherwise operationally constrained in order for UMERC to comply with the clean energy standard. The Commission and Commission Staff have undertaken this work through MISO and ATC engagement in an updated transmission study, public engagement in the UP, one-on-one meetings, and questionnaire responses from UP utilities and industrial customers.

Public Comment: Voices of the UP

The experiences of UP customers in the energy space are unique and the concerns around energy supply and costs arising from those experiences are important when considering implementation of the 2023 energy laws. To ensure these experiences are considered and concerns are addressed, the Commission has worked to include the voices of UP utility customers in preparing this report. As part of this process, the Commission solicited written comments from interested persons in MPSC Case No.

U-21572. Additionally, Commissioners and Staff engaged in discussions with utilities, customers, Tribes, elected officials, and industry representatives from across the UP to understand their perspectives relative to implementing the 2023 energy laws. This outreach and engagement included multiple visits to the UP where Commissioners and Staff met with individuals from each of these constituencies and held a public hearing in Marquette, MI, to take public comment on the study.

Twenty-four members of the public and interested parties submitted written comments in Case No. U-21572[1] and several dozen individuals spoke at the public hearing. Many of these comments shared similar themes including the importance of energy affordability and a desire to protect the unique natural beauty of the UP from excessive development. Commenters shared that the beauty of the UP is something worth preserving and that great care should be taken for the protection of our collective natural treasures.

Commenters also shared several thoughts concerning affordability which are briefly summarized here. They shared that energy affordability is a primary concern for most utility customers, especially those in the UP, and any energy solution for the UP must be affordable for the people who will ultimately pay for it. The UP's grid is currently reliable and operational, but commenters pointed out that many of the investments are still being paid for by UP customers. The shift to new investments while still paying for the ones already made creates concerns about affordability. Commenters shared concerns that the RICE units operated by UMERC and MBLP were only brought into service within the last few years and are being paid off over their expected useful life of 30 years. They noted that these units are relatively easy to maintain and rebuild, and therefore could continue to operate well beyond their installed useful life. Commenters expressed great concern about affordability and local choice for solution development. In the move toward a clean energy future, affordability is vital. Energy waste reduction (EWR) and energy efficiency (EE) are crucial in addition to building a local workforce for clean energy jobs. Commenters believe that the Commission and utilities must build trust and meet people's real needs for EWR to be successful. The public also must be informed of existing assistance programs. Finally, commenters reminded the Commission that any decision made regarding the UP's electric energy system will have an impact on everyday people and that must not be forgotten.

The comments are provided in their entirety in Appendix B.

The UP is also home to five federally recognized Tribes: Bay Mills Indian Community, Hannahville Indian Community, Keweenaw Bay Indian Community, Lac Vieux Desert Band of Lake Superior Chippewa, and Sault Ste. Marie Tribe of Chippewa Indians. Some Tribes and Tribal members shared their desire to develop their own clean

[1] Michigan Public Service Commission, Case No. U-21572, https://mi-psc.my.site.com/s/global-search/21572, retrieved 11/25/2024.

energy resources as well as concerns that included preservation of their land, culture, and resources.

Staff Interviews and Solicitations

In addition to working with MISO and ATC on an updated transmission study and soliciting public comment, Commission Staff engaged with multiple UP utilities in the course of preparing this report, including UMERC, UPPCo, Northern States Power Company – Wisconsin (NSP-W), Cloverland Electric Cooperative (Cloverland), the Marquette Board of Light and Power (MBLP), the Michigan Public Power Association (MPPA), WPPI, the City of Escanaba, the Michigan Municipal Electric Association (MMEA), and Wisconsin Public Service Corporation. This engagement included discussions, meetings, case docket comments, and soliciting information via questionnaires regarding several topics of this report. All nonconfidential written information that was provided directly to Staff from businesses and load-serving entities is included in the appendices of this report.

UP Energy Considerations Required by PA 235

As acknowledged by the Legislature, the energy landscape of the UP is different from that of the Lower Peninsula. This is due, in part, to the UP's population density and the number of utilities serving its population.

The Unique Conditions Influencing Demand, Electric Generation, and Transmission in the Upper Peninsula

Population

Today, the UP is home to 21 load-serving entities (electric utilities): 3 investor-owned utilities, 4 electric cooperatives, and 14 municipally owned electric utilities. Together, these 19 utilities serve approximately 200,000 customers. The three investor-owned utilities are NSP-W, a subsidiary of Xcel Energy; UMERC, a subsidiary of WEC Energy Group; and UPPCo, which is the largest of the UP investor-owned utilities with just over 53,000 customers. The four electric cooperatives are Alger Delta, Bayfield, Cloverland, and Ontonagon County Rural Electrification Association, with Cloverland being the largest at 43,000 customers. Of the 14 municipal electric utilities, Marquette Board of Light and Power is the largest, serving over 17,000 customers. Escanaba is the second largest at 7,000 customers. Half of UP customers are served by a municipal electric utility or a cooperative. 10% of Lower Peninsula customers are served by a municipal electric utility or cooperative.[2]

[2] Customer data taken from EIA Form 861.

According to the 2020 census, approximately 300,000 people live in the Upper Peninsula. While the UP's more than 16,000 square miles accounts for approximately 30% of the state's land mass, only 3% of the state's population calls the UP home. The difference in population between the UP and the Lower Peninsula is mirrored in differences in electricity demand between the two peninsulas. In 2023, UP electric demand was approximately 4.2 million megawatt hours (MWh) across approximately 200,000 customers; while in the Lower Peninsula, electric demand exceeded 100.1 million MWh across 4.8 million customers.

Population density is also a significant difference between the peninsulas that impacts the energy landscape. With fewer people per square mile in the UP (less than 19 people per square mile in the UP vs. 240 people per square mile in the Lower Peninsula), there are fewer customers per line mile on the energy system which increases the cost per customer.

Population, land area, and total number of utilities serving the UP population are all differences that contribute to an energy landscape in the UP that is different from that in the Lower Peninsula. However, to understand and analyze the UP's energy landscape, it is critical to understand customer demand as well as the history and development of the UP's energy system. The development of this system was, in part, a direct result of the development of different industries in the UP, and this development continues to be reflected in how the UP system is used by customers.

Demand

Another defining factor of the UP is the portion of the UP's energy demand that comes from industrial customers. While total UP energy demand in 2023 exceeded 4 million MWh, more than half of that demand (2.3 million MWh) was attributable to industrial customers. Comparatively, in the Lower Peninsula, only 30% of the electric demand comes from industrial customers.

Industrial customers in the UP fall into several broad categories. Verso Corporation and Systems Control have substantial manufacturing operations in Escanaba and Iron Mountain, respectively. Forestry and the wood products industry have long been present in the UP and continue to have a presence there. Besse Forest Products Group, Louisiana-Pacific Corporation, Neenah Paper, and Billerud operate various facilities across the UP. Additionally, the UP is home to eight universities and colleges and four major hospitals. Tourism and recreation are also a significant part of the UP's economy with facilities dotted across the peninsula.

The Cleveland-Cliffs Tilden Mine has the largest electric load in the UP. The mine, which began operations in 1965, is an open-pit iron mine located southwest of the City of Marquette. In 2021, Tilden Mine produced 7.7 million long tons of iron ore pellets per year, which are transported by rail to Marquette, loaded on freighters, and sent to Cleveland-Cliffs steel mill facilities via the Great Lakes.[3] Mining the ore and

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[3] Technical Report Summary on the Tilden Property, Michigan, USA S-K 1300 Report, p. 1.

processing it into pellets is an energy intensive, continuously running process. Energy expenses account for 25% of Tilden's costs. All told, the direct mining and processing operations, along with related transportation, operations employ more than 1,000 people in the UP. Today, the Tilden Mine makes up more than half of UMERC's total load.

UP residential load is also a bit different from the Lower Peninsula. Residential customers in the UP utilize air conditioning in the summer months less than customers in the Lower Peninsula due to the lower summer temperatures. The combined result of lower summer residential customer load and a larger percentage of total electric load being industrial customers is that the UP winter and summer electric peaks are not distinctly different. There are even years where the UP experiences peak electrical load in the winter.

Electric Generation

The electrical system of the UP developed around the distinct industrial load centers and the surrounding population. This generation largely took the form of hydroelectric facilities, small diesel generators, and coal plants. As large industry developed across the UP, including mining and paper milling, electric generation developed to support their operations. Over time, these industry-owned facilities were sold to utilities resulting in an intertwined electrical system that connects dispersed load pockets that are geographically and electrically distinct. Although the use of coal-fired electric generation facilities in the UP has ceased, the islanded nature of generation and the load centers it serves has remained largely unchanged.

Generation Changes Since RICE Approval

UMERC requested approval for procurement of 100 MW of solar generation in its 2021 Integrated Resource Plan (IRP) application in Case No. U-21081.[4] The Commission approved the settlement agreement between all parties in the case in May 2022. UMERC evaluated the acquisition of solar through its request for proposal (RFP). UMERC evaluated all projects of varying sizes that were available in the MISO interconnection queue within the UP.[5] At the end of 2023, UMERC sought approval to purchase the Renegade Solar project, a 100 MW solar generation facility. The expected in-service date of the Renegade Solar project is the end of 2026.[6] The Commission's April 11, 2024, Order in Case No. U-21081 approved UMERC's acquisition of the project.

On June 21, 2024, the Upper Peninsula Power Company (UPPCo) filed an application requesting approval of a power purchase agreement (PPA) to acquire 62.5 MW of the output of the Groveland Mine Solar project in Dickinson County housed at the

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[4] MPSC Case No. U-21081, Direct Testimony and Exhibits of UMERC witness Richard F. Stasik, p. 4.
[5] Order May 12, 2022, Case No. U-21081, Exhibit A, p. 4.
[6] Application December 1, 2023, Case No. U-21081, p. 6.

site of a long-vacant iron mine. This request is consistent with the Company's 2019 Integrated Resource Plan in Case No. U-20350 that included the acquisition of a total 125 MW of solar capacity. After evaluation of the responses to its 2020 RFP, UPPCo chose the Groveland Mine Solar project. This PPA was approved by the Commission on August 22, 2024, in Case No. U-20350.

UPPCo also intends to acquire 62.5 MW of solar from a Build-Transfer Agreement with the purchase of the Republic Solar, a 62.5 MW solar facility to be located in Marquette County.[7] This project application was submitted to the Commission for approval on November 21, 2024, and is currently pending before the Commission.

Based on the energy storage targets established by PA 235, Staff expects there will be approximately 60 MW of energy storage added across the Upper Peninsula in the coming years. However, the storage locations are unknown. Given the smaller size of many of the UP electric providers, Staff expects that some of this added storage capacity will be distribution-connected.

Generation Siting Difficulties

The UP has not been immune to the challenges related to siting renewable energy facilities experienced by Lower Peninsula utilities and developers. For example, it took UPPCo until 2024 to obtain a viable contract for some of the solar approved in the company's 2019 IRP in part due to siting constraints. The initial 125 MW of solar that UPPCo originally intended to contract with was canceled due to the project's failure to receive the required land use permits. A similar situation happened with a 40 MW wind project. After having all RFP respondents resubmit bids, as described in the preceding section, UPPCo plans to contract 62.5 MW of company-owned solar from the Republic Solar project and has gained Commission approval for a 62.5 MW solar PPA from the Groveland Solar project.[8] Due largely to permitting issues, it took UPPCo 4 years to procure 125 MW of renewables.

In addition to siting challenges, when compared to prices in the Lower Peninsula, solar energy project development tends to be more expensive in the UP. There are many reasons for this price difference, including: UP geology which requires solar facilities to be ballasted rather than anchored in the ground; lower capacity factors; and more expensive construction logistics. The combination of these differences would result in a similar sized project in the UP being more expensive, potentially resulting in fewer projects planned in the UP.

Impact of a Shifting Generation Mix: Decarbonization in the UP

The Upper Peninsula has decarbonized faster than the Lower Peninsula. In 2019, with the closure of PIPP by UMERC and MBPL's retirement of the Shiras Steam Power

[7] MPSC Case No. U-20350, IRP Status Report June 20, 2024, p. 5.
[8] MPSC Case No. U-20235 IRP Status Report June 2024, 2024, p. 2-5.

Plant, the UP eliminated all its coal-fired generation – an achievement that was reached more than a decade before the Lower Peninsula is expected to meet this benchmark. With the UP's significant hydroelectric generation resources and, more recently, UMERC's acquisition of Renegade Solar and UPPCO's acquisition of Groveland Solar and planned acquisition of Republic Solar, the UP is ahead of the Lower Peninsula in terms of both decarbonization and overall renewable resource portfolio. Even before these solar resources come online, the UP electric sector has reduced its CO_2 emissions by approximately 71% between 2013 and 2022, according to U.S. Energy Information Administration (EIA) data. While the Clean Energy Standard is not based on a baseline year, it is important to acknowledge the UP utilities' accomplishments to date.

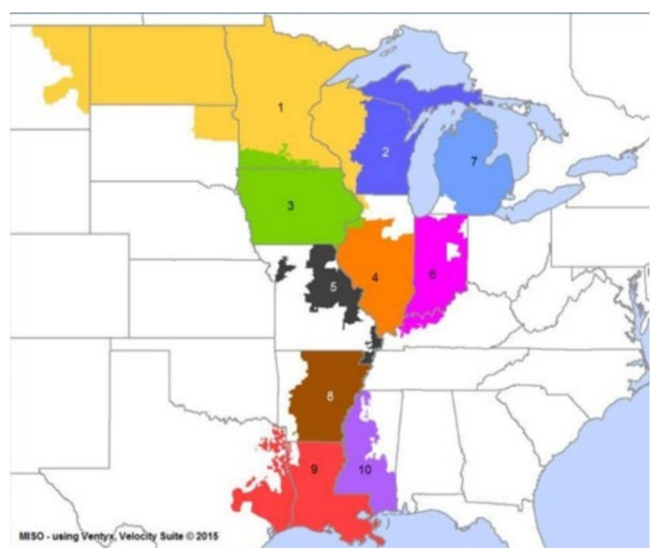
Transmission

The UP's transmission system has been the subject of several studies over the last 20 years.

Since the early 2000s, the transmission system across much of the United States has been operated by RTOs or Independent System Operators (ISOs). These organizations have many functions, one of the most important being to ensure the reliability and stability of the transmission system. All of the UP is within the Midcontinent Independent System Operator (MISO) (see Figure 1) and much of the UP is in MISO Zone 2[9] (see Figure 2). MISO conducts studies and Staff can make recommendations regarding projects to improve system reliability. These projects are then reviewed by a Board of Directors that makes decisions regarding project

Figure 1: MISO Regions

Figure 2: MISO Zones

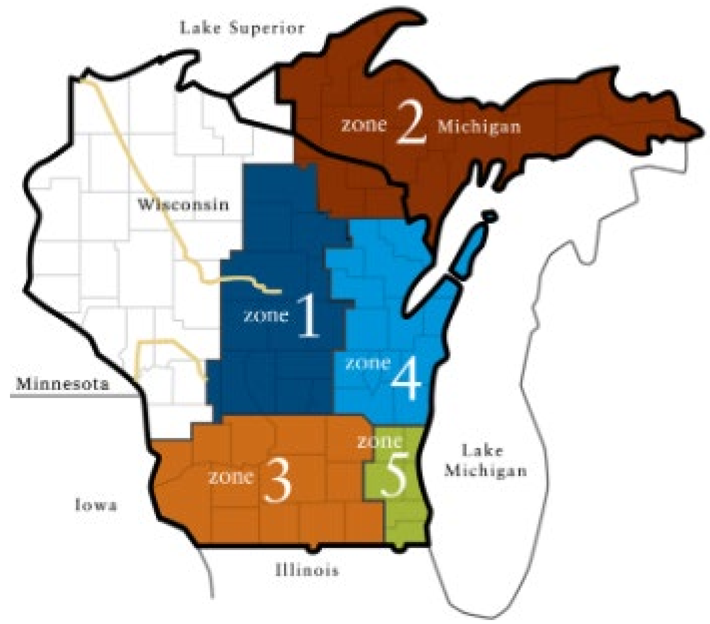


[9] A portion of the far Western UP, served by NSP and Bayfield Electric Co-op, falls within MISO Zone 1. Together, NSP and Bayfield serve approximately 9,000 customers.

approval. Costs for approved projects are determined based on the approved MISO tariffs. These tariffs are approved by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over all the RTOs and ISOs operating across the country.

American Transmission Company (ATC) owns and operates approximately 10,000 miles of transmission across five ATC Planning Zones. Michigan's UP is a part of ATC's planning Zone 2 where ATC operates 138 kV and 69 kV lines.[10] A map of ATC Planning Zones is provided as Figure 3.

Figure 3: ATC Planning Zones



Following a study conducted by MISO into the ATC UP system, in 2011 the MISO Board of Directors approved the Mackinac High Voltage Direct Current (HVDC) Flow-Control Project.[11] Due to weak transmission system conditions on both sides of the Straits of Mackinac, ATC constructed a Back-to-Back Voltage Source Converter HVDC[12] station. This technology is used to control flows, including loop flows around Lake Michigan, and provides reliability and frequency stability between Michigan's Lower and Upper Peninsulas. The Mackinac HVDC Converter Station was placed in service in 2014.

Transmission owners and operators need to ensure that the system can continue to operate during both planned and unplanned outages. This requires that system operators and owners study the system to ensure that the system will operate under a variety of conditions. Ongoing system planning is crucial to ensuring that the transmission system can support the needs of customers and MISO facilitates an annual planning process to identify concerns and devise solutions to address them. During regular planning that occurred in 2012, ATC and MISO identified "urgent reliability concerns" on the ATC transmission system.[13]

In transmission system planning, a contingency is an event that may occur and impact the system causing it to operate differently than it does under normal conditions. When ATC studied the transmission in the UP system, no single

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[10] The western most edge of the UP is operated by NSP-W and there is no transmission infrastructure in Michigan, only distribution system infrastructure.
[11] Mackinac HVDC Flow-Control Project Fact Sheet, http://www.atc-projects.com/wp-content/uploads/2012/08/StraitsFlow-FactSheet.pdf, retrieved August 14, 2024.
[12] HVDC is an abbreviation for high voltage direct current
[13] MPSC Case No. U-17272 Application, p. 2.

contingency (planned or unplanned) on its own caused a problem on the system. However, when ATC studied the single contingency analysis in conjunction with a planned outage (for instance, an outage for system maintenance where power is routed through a different circuit), as well as under multiple contingency outages, the study showed that the system was vulnerable to a loss of load (i.e. there would not be enough electricity to meet demand due to the transmission system failure).[14] The studied scenarios were not just hypothetical. In May of 2011, a single contingency occurred during a planned outage. In that instance, lightning struck a double circuit 138 kV line. While this strike alone would not have been enough to cause the resulting outage, at the time of the strike, a separate 345 kV line was offline for maintenance.[15] The resulting outage impacted the western two-thirds of the UP.[16]

Following the identification of this urgent reliability concern, ATC sought a Certificate of Public Convenience and Necessity (CPCN) in MPSC Case No. U-17272 for the construction of a new 138 kV transmission line.[17] In that case, ATC proposed the Holmes to Old Mead Road project, which is a 58 mile long 138 kV line from Holmes substation, near the Wisconsin border in Menominee County, to the Escanaba area.[18] Ultimately, the Commission approved an uncontested settlement agreement and ATC built the line,[19] which was placed into service on August 11, 2016.[20]

One benefit that RTOs and ISOs provide, in addition to monitoring the transmission system within their respective footprints, is to allow for the movement of electricity across the footprint in an economical manner. One type of electric generation can cost more or less than another type and the ability of the RTOs and ISOs to project anticipated demand and to direct generation owners to start their generating units (or “dispatch” them) or to turn them off means that utilities can take advantage of lower cost generation which saves their customers money. While several factors are taken into consideration when dispatching generating units, the RTOs and ISOs use “economic dispatch” to the extent they are able. This means they dispatch the lowest cost available generation first and then work up to more expensive generation until customer demand is met.

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[14] MPSC Case No. U-17272 Direct Testimony and Exhibits of ATC witness Stephen D. Feak, p. 16.
[15] Id. at p. 7.
[16] ATC Restarting electric system in Michigan Upper Peninsula. ATC News release issued May 10, 2011. Available at https://www.atc-projects.com/news-releases/atc-restarting-electric-system-in-michigans-upper-peninsula/ retrieved October 25, 2024.
[17] Public Act 30 of 1995 requires that a transmission company apply to the Commission for a Certificate of Public Convenience and Necessity (CPCN) before constructing a major transmission line. A major transmission line is 5 miles or more in length through which electricity is transferred at system bulk supply voltage of 345 kilovolts or more. A transmission company may voluntarily file an application with the Commission for a CPCN for a proposed transmission line other than a major transmission line.
[18] MPSC Case No. U-17272 Direct Testimony and Exhibits of ATC witness Jane L. Petras, p. 7.
[19] MPSC Case No. U-17272 Order dated January 23, 2014.
[20] MPSC Case No. U-17272 Project In-Service Notification filed August 23, 2016.

The ability to dispatch generation across the footprint can be limited by circumstances on the transmission system referred to as “transmission constraints.” When there is transmission congestion or reliability needs that result in the RTO or ISO needing to dispatch generation out of economic merit order (i.e., dispatching a more expensive generating unit before dispatching a less expensive unit) in order to maintain system operations, this is referred to as a binding constraint. An area that experiences a binding constraint more than 500 hours in a 12-month period is referred to as a “narrowly constrained area.”

The Upper Peninsula is contained in the MISO-defined North Wisconsin and Upper Michigan System Narrowly Constrained Area (NWUMS NCA). In 2021, NWUMS NCA experienced 1,659 hours of binding constraint. In 2023 (the most recently published numbers), NWUMS NCA experienced 1,785 hours of binding constraint. There have been several transmission studies of the UP which have identified potential solutions that could have alleviated this condition.[21]

In 2016, the Michigan Agency for Energy (MAE) and the Michigan Public Service Commission requested that MISO conduct an exploratory study for informational purposes. The study, called MISO Michigan Phase II Study, was originally intended to analyze production cost savings, reliability, and resource adequacy benefits of potential transmission expansion to better connect the Eastern Upper Peninsula to Ontario at Sault Ste. Marie. MISO expanded that study to consider the viability of generation alternatives in the Eastern UP and the Lower Peninsula directly across the Straits of Mackinac. Some of the transmission alternatives studied extended far west into the UP, while others were firmly in the Eastern UP. The study found that strengthening the transmission network in the Eastern UP did not provide an economic benefit; none of the transmission upgrades that were studied to connect generation in the Northern Lower Peninsula or Ontario provided a benefit-cost ratio greater than one.[22] This means that relieving the UP of being narrowly constrained though transmission expansion was deemed uneconomical at the time of the study.

In September 2016, ATC voluntarily performed a high level, steady-state screening of transmission facilities in the Upper Peninsula. This was done to assist generation developers with the preliminary identification of potential locations where existing transmission facilities may have been able to accommodate new and/or additional generation capacity. This study analyzed possible interconnection points under single contingency analysis. Those that were not suitable for generation interconnection were eliminated. Those that appeared to be able to accommodate

[21] MISO IMM, Narrow Constrained Area Threshold Reports 2021, 2023, 2024, retrieved 11/22/2024.
https://cdn.misoenergy.org/2021_NCA_Threshold_Update554960.pdf
https://cdn.misoenergy.org/2023_NCA_Threshold_Update_FINAL629129.doc
https://cdn.misoenergy.org/2024_NCA_Threshold_Update633129.pdf
[22] Appendix H

100 MW or more were studied under multiple contingency analysis.[23] Most of the interconnection points that were capable of hosting generation in 2016 were able to host only a small amount of generation, between 15-85 MW of generation. There were fewer than 10 interconnection locations that were capable of hosting 100 MW or more and were possible interconnection points for generation to replace PIPP upon retirement. The final report is attached as Appendix I.

Transmission Changes Since 2016

The transmission system is ever changing. As load increases or decreases, generation comes online or retires, or as individual assets of the transmission system age, the transmission system must change in response to function properly. The transmission system of the UP has changed at a slower rate than that of the Lower Peninsula.

ATC conducts an annual 10-Year Assessment. This assessment is used to determine what projects are needed to maintain system baseline reliability,[24] facilitate generation interconnections,[25] and conduct other projects such as age and condition or local reliability needs assessments. Staff cross-referenced the annual ATC 10-Year Assessment[26] from 2017 through 2023 with MISO's list of in-service transmission projects to identify all the projects that have been completed in the UP since the MISO and ATC studies of the UP transmission system started in 2016 and completed in 2017. Of the projects completed, only one was considered a baseline reliability project. The other two projects were required to allow new generation to come online and were identified through the MISO Generation Interconnection Queue process. These projects are known as Generation Interconnection Projects. Since 2017, there have been four age and condition projects, which replace aging or damaged transmission assets. The most notable of these projects, and the largest project completed in the UP since 2017, is the replacement of the underwater electrical cables in the Straits of Mackinac which were severed by an anchor strike in 2018. There are six projects that have been completed in the UP that satisfied either local reliability needs or other local needs. As suggested by the names of these categories, the projects are needed due to local changes or minor changes needed to substations. These projects are not expected to have a major effect on the wider transmission system. The largest of these projects was to upgrade the

[23]Contingency analysis refers to a method for evaluating the impact of problems on the transmission system such as generation power outages or transmission line outages. Multiple contingency analysis is analyzing more than one contingency happening at the same time.
[24] Baseline reliability projects are transmission projects that are needed to properly maintain the transmission system and are required to meet NERC planning requirements.
[25] Generation Interconnection Projects (GIP)s include facilities to interconnect to the grid and any upgrades to the transmission system that are required due to modeled negative effects of increased injection of electricity with the interconnected new generation.
[26] https://www.atc10yearplan.com/, retrieved 11/21/2024.

communication network used to control and monitor the transmission system and has been completed.

In general, the changes to the UP transmission system have strengthened the system's reliability under its current configuration. However, these projects have not resulted in significant changes in ability to flow energy into, across, and out of the UP. Therefore, the Commission expects that these earlier studies still have value in understanding the UP transmission system's capabilities. However, as part of the Commission's response to the directive in PA 235, further study is ongoing with ATC and MISO, with final results expected in 2025. These studies are aimed at better understanding potential impacts of generation transformation across the broader UP.

The Unique Role of the RICE Units Placed in Service to Facilitate the Retirement of Coal-fired Generation Located in the UP After the RTO Imposed SSR Charges

The build out and design of the UP's transmission system was directly impacted by the generating facilities used to meet the energy needs of UP customers. The largest facility was the Presque Isle Power Plant (PIPP). PIPP was a coal-fired power plant originally built in the 1950s by Cleveland-Cliffs to serve both the Tilden and the Empire Mines. The size of the plant allowed it to serve other loads in the UP, and it was the main source of electricity generation for the peninsula. Subsequently, the transmission system was built up around PIPP and the facility became critical to transmission system operations.

As mentioned above, PIPP was sold to UPPCo in the 1980s, then later to Wisconsin Electric Power Company (WEPCo). In 2013, Cleveland-Cliffs began to contract for electric service from an alternative energy supplier (AES) to serve its mining operations, which resulted in WEPCo announcing it would suspend operations at PIPP. Cleveland-Cliffs entered into an agreement with WEPCo to return to regulated service in February 2015, but the retirement of PIPP and need for a replacement solution was imminent.[27]

When a utility in the MISO territory plans to retire a generation facility, it must file an Attachment Y notice with MISO which triggers a study of the role of the generator in the transmission system. If retirement of the generator will compromise transmission system operations, the generator is designated as a system support resource (SSR), and it may not be retired until a solution can be implemented to maintain transmission system operations. There can be a significant cost impact to customers when a generator is declared an SSR. While operational costs for a generator are traditionally spread over a number of years, costs for an SSR are paid

[27] Case No. U-17829.
https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068t0000001UNu6AAG.

by ratepayers in the year that they are incurred. The result can be a drastic increase in rates while the SSR is operational.

When WEPCo submitted the Attachment Y to MISO seeking to retire PIPP, the Attachment Y reliability study determined that PIPP could not retire without violating the North American Electric Reliability Council's transmission planning criteria and compromising transmission system operations.[28] For this reason, and because a mitigating solution could not be implemented before the proposed retirement, PIPP was designated as an SSR. PIPP SSR payments ultimately caused a 20% increase in rates in the UP while the SSR payments were ongoing.[29]

In response to WEPCo's desire to retire PIPP, but prior to PIPP's SSR designation, MISO performed a study to determine how much generation would be required to maintain system reliability if PIPP were to retire. The PIPP Generator Replacement Screening Study looked at many different variables and combined them into four scenarios with many different sensitivities.[30] After review of the expected operation of the ITC HVDC device, discussed earlier, and the transmission upgrades that were expected to be implemented at that time, MISO determined that the most likely future state of the transmission system was one where the HVDC device did not flow power into the UP and therefore approved two reinforcement projects.[31] With the approval of these projects, there was a need for between 80 MW to 370 MW of new generation to facilitate the retirement of PIPP. The precise amount varied based on the number of units and electric system loading. MISO determined that if there were four units at a generation site between 80 MW and 250 MW of generation, it would be adequate to allow PIPP's retirement. The data showed as the number of units at a generation site increased, the amount of generation needed decreased, regardless of loading conditions.

In late 2016, WEC Energy Group created the load serving entity, Upper Michigan Energy Resources Corporation (UMERC), a wholly owned subsidiary utility serving only Michigan customers.[32] UMERC was created as a Michigan-only jurisdiction

[28] MPSC Case No. U-18224 Direct Testimony and Exhibits of Daniel P. Krueger, Exhibit A-_(DKP-1), p. 8-9, MISO Tariff Section 32.2.7.a, MISO Business Practice Manual, p. 152-156.
[29] MPSC Case No. U-18224 Direct Testimony and Exhibits of Daniel P. Krueger, Exhibit A-_(DKP-1), p. 8-9.
[30] MPSC Case No. U-18224 Direct Testimony and Exhibits of Joann Henry, Exhibit A-__(JH-1).
[31] These transmission projects considered in the study were not a total transmission solution to PIPP retirement but were transmission projects that were already planned and would be required even with a generation replacement for PIPP.
[32] WEC Energy Group agreed to seek the formation of UMERC as a Michigan-only utility as part of the multi-party agreement that resulted in the "Upper Michigan Energy Solution". This agreement was memorialized in the Amended and Restated Settlement Agreement (ARSA) approved by the Commission in Case No. U-17682, when it approved WEC's acquisition of Integrys. As part of the ARSA, it was agreed that (1) WEC would develop a Michigan-only jurisdictional utility and seek Commission approval for that utility and (2) the Michigan-only jurisdictional utility would develop "new, clean generation" that would provide a "long term solution" to the UP's energy needs.

utility to facilitate the ability for UP solutions independent of Wisconsin that would be wholly paid for by UP customers. In response to the PIPP Generator Replacement Screening study, UMERC proposed to build several Reciprocating Internal Combustion Engine (RICE) units to replace PIPP. These types of generating units are well suited to providing reliable power at all times because RICE units are modular generation units of between 9-20 MW[33]. The modular nature of the units means that if there are several units at a single location and one unit experiences an outage, the outage will have less of an effect on the transmission system because the remaining units continue to operate independently. Natural gas RICE units, like those proposed by UMERC, also have a lower heat rate compared with traditional natural gas-fired combustion turbines which makes them more efficient and economical to operate.[34] RICE units are also well suited to operating in conjunction with a high renewable energy portfolio because they have very fast ramp rates, are dispatchable at all times, and are not limited to short operating durations.

On January 30, 2017, in Case No. U-18224, UMERC applied for a certificate of necessity, pursuant to MCL 460.6s, for two RICE facilities. Following a contested case proceeding, the Commission approved UMERC's request to construct the RICE facilities, with generating capacity totaling 183 MW at a cost of up to $277,200,000.[35,36] The approved facilities ultimately became the 7-unit, 131.6 MW, F.D. Kuester Generation Station in Negaunee Township and the 3-unit, 56.4 MW, A.J. Mihm Generation Station in Baraga Township. These facilities began commercial operations on March 31, 2019.[37]

In addition to replacing a portion of the generating capacity of PIPP, the location of the RICE facilities at two different sites in the Upper Peninsula also eliminated the need for the construction of more costly transmission solutions to facilitate PIPP's retirement, which would have required building $373 million[38] in transmission

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In June 2016, WEC filed an application in Case No. U-18061 seeking authorization to form UMERC and transfer the Michigan-based non-generation assets of Wisconsin Electric and Wisconsin Public Service Corporation to UMERC. On October 19, 2016, a unanimous settlement was reached to resolve all the issues in this proceeding, and the Commission approved that settlement on December 9, 2016. UMERC was formed and began operating effective January 1, 2017. All Michigan-located customers of Wisconsin Electric and Wisconsin Public Service Corporation were transferred to UMERC effective on that date except the Tilden Mine, which remained a Wisconsin Electric customer until the RICE units were placed in service.

[33] MPSC Case No. U-18224 Direct Testimony and Exhibits of UMERC witness Joann Henry, p. 11.

[34] Heat rate is the amount of heat produced by the fuel through the combustion process that is required to produce one MWh of energy. The lower the heat rate, the more efficient the thermal generator.

[35] October 24, 2017 MPSC Order in Case No. U-18224, p. 118

[36] https://www.michigan.gov/-/media/Project/Websites/mpsc/consumer/info/briefs/MPSC_Issue_Brief_--_Upper_Peninsula_Generation_Project.pdf?rev=567425db07a446dda68f3c9aec23f282

[37] MPSC Case No. U-18224 UP Gen Project annual Progress Report, p. 2, EIA Form 860 2022.

[38] Project estimates were determined in 2019 and have not subsequently been adjusted for inflation.

upgrades, which included the "Plains to National" 138 kV line.[39] These transmission projects would have taken substantially longer to build and place in service than the UMERC RICE generators resulting in a longer period of time that UP customers would be subject to SSR payments. Approval of the UMERC RICE units allowed for the cancellation of all ATC transmission projects that were a partial solution to the PIPP SSR, saving UP customers an estimated $373 million in transmission upgrade costs and ended all future SSR payments.[40]

Just as importantly, the development of UMERC's RICE units has helped maintain reliability for the UP. Had PIPP retired before a solution was implemented, there would have been periods of controlled load curtailment in order to prevent a collapse of the UP transmission system. Controlled curtailment, or loss of load, could have meant that specific customers (i.e., the Tilden Mine or other large energy users) would not be able to run or could have resulted in widespread brownouts or blackouts. How widespread these loss of load events would have been, and their duration, is not known, but the RICE units have proven to be a robust solution that prevented such a scenario. The RICE units provide both generation and a solution to the transmission system challenges. They fulfill a vital role in ensuring the reliability of the UP's electric system.

At approximately the same time that UMERC was considering retiring PIPP, the Marquette Board of Light and Power was considering shutting down its coal-fired Shiras Steam Plant. The Shiras Plant was built in the 1960s, with additional units added in the 1970s. Shiras had become less reliable and less economical due to both the age of the units and market forces. MBLP considered many possible replacements, including renewable generation, natural gas, coal generation, and bilateral contracts for energy and capacity. Due to transmission constraints at the time, ATC did not have enough transmission capacity to provide MBLP with firm service, rendering any options for a bilateral contract moot and limiting MBLP to a generation solution. MBLP sought a solution that was dispatchable to avoid load curtailment.[41] MBLP elected to build RICE units due to a combination of reliability and affordability factors, and its ability to run on both natural gas and fuel oil, which provided fuel security during times of fuel price fluctuation. The result was the 51 MW Marquette Energy Center, which was brought online in 2017.

MBLP dispatches these units when the cost to purchase energy from MISO is higher than the cost to run the RICE units. By removing their load from the MISO market, MBLP is reducing the severity and duration of price spikes as well as transmission congestion in the UP while also ensuring MBLP customers have reliable electricity if ATC's transmission system is experiencing higher levels of congestion at times of elevated demand across the UP.

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[39] MPSC Case No. U-18224 Direct Testimony and Exhibits of Joann Henry, p. 6.
[40] MPSC Case No. U-18224 UP Gen Project annual Progress Report, p. 2.
[41] Load curtailment is synonymous with load shed and means the involuntary reduction of load on the system. Load curtailment typically involves restricting power to industrial customers first before impacting residential customers.

While additional information is expected as part of the ongoing study with MISO, any future scenario that would replace the UP RICE units will need to be equally robust and cannot introduce service interruptions during a transition period.

The Upper Michigan Energy Resources Corporation and Cleveland-Cliffs

Cleveland-Cliffs was uniquely tied to PIPP as its builder and original owner. Similarly, the Cleveland-Cliffs Tilden Mine has a unique relationship with UMERC and the RICE units – a relationship that enabled their development and secured transmission system benefits across the entire UP.

The Commission's Order on October 25, 2017, provided approval of two key components to ensuring electric reliability for UP customers. In that order, the Commission approved UMERC's application for a certificate of necessity pursuant to MCL 460.6s for two RICE facilities (the UP Generation Project), one in Baraga Township and one in Negaunee Township. In its approval, the Commission stated that, "UMERC demonstrated that the UP Generation Project is the most reasonable and prudent means of meeting the power need relative to other options." Also, "[f]Following the closure of PIPP, the UP Generation Project will serve a unique need to maintain reliability in the UP without incurring additional transmission costs." The Commission's Order also approved a special contract between UMERC and Tilden, the Tilden Mine Special Contract (TMSC). This contract was the final critical milestone to ensuring the RICE units came online, facilitating the retirement of PIPP, the cancellation of the SSR, and obviating the need for other, more costly transmission system upgrades – all of which would have impacted UP customer rates. Pursuant to the contract, UMERC would pay 100% of the capital cost for the RICE units. However, Tilden would reimburse UMERC for 50% of the capital costs on a levelized basis over the 20-year period of the special contract.[42]

Tilden's investment in the RICE units is not the only benefit UP ratepayers receive from the relationship between Tilden and UMERC. Almost all of the Tilden Mine's load is curtailable, which means that the load can be proactively reduced as part of MISO's emergency planning procedures prior to involuntary load shed if there is a system emergency event. The Tilden Mine load is also a capacity resource. While capacity resources may generally be thought of as generating resources, the ability to reduce load on demand can be credited to utilities as a capacity resource. Pursuant to the TMSC, Tilden's load can be curtailed under certain conditions, limited to MISO emergency procedures (i.e., unplanned situations where load must be reduced in order to maintain transmission system operations) and "non-emergency conditions related to transmission outages or other bulk system conditions." This does not include being curtailable for economic reasons, for example, curtailment that provides an economic benefit to UMERC or Tilden.[43]

[42] Appendix C
[43] Appendix C

Due to Tilden Mine's curtailment status, UMERC can use the Tilden Mine's curtailment as a capacity credit that is equal to 50% of the UMERC's planning load share. This saves UMERC customers money because, absent that capacity credit for Tilden Mine's curtailment capability, UMERC customers would have increased costs to acquire capacity to satisfy its capacity obligation.[44] [45]

This contract also provides UMERC and its ratepayers the capacity of the RICE units, less the small portion of non-curtailable mine load. The RICE unit capacity is critical to meeting MISO's Planning Reserve Margin Requirement and the annual capacity demonstration established in MCL 460.6W. UMERC customers also receive the benefits of ancillary services and energy for any difference in energy output between what the RICE units are committed to in the MISO market and the energy required by Tilden for its mine operation.[46] Furthermore, as demonstrated by the RICE units providing a solution that allowed the Presque Isle Power Plant to retire, the presence of the RICE units have additional benefits for the UP including providing system reliability, system stability, and reduced transmission congestion, which results in lower local energy prices.[47]

While the details of both the size and profile of Tilden's load are confidential, the load is significant. Staff engaged Cleveland-Cliffs in several discussions and asked a number of questions to gain an understanding of Tilden's impact on the UP electric system and economy. Based upon information gathered through these interactions, Cleveland-Cliffs does not expect that there will be any changes to the Tilden load for the duration of the special contract with UMERC, which runs through 2039.[48] Tilden also does not anticipate any major electrification projects that would significantly increase its load in the UP or alter the broader UP energy dynamics.[49]

Changes in Electric Demand, Including Changes from Mining-Related Economic Development Projects, That May Influence the Utilization of the Reciprocating Internal Combustion Units

Public Policy

Understanding anticipated load changes is critical to appropriately assessing opportunities for compliance with the 2023 energy laws and any potential compliance challenges. While individual customer behavior, including behaviors and

[44] Capacity Obligation is the amount of capacity an electric provider must acquire to meet the MCL 460.6W capacity demonstration requirements.
[45] MPSC Case No. U-18224 Testimony and Exhibits of UMERC witness James O. Sherman, p. 7.
[46] MPSC Case No. U-18224 Testimony and Exhibits of UMERC witness James O. Sherman, p. 9.
[47] *Id.*
[48] Appendix C
[49] Appendix C

decisions of both residential and industrial customers, will impact future load changes, public policy (like the 2023 energy laws) will also play a role. One public policy initiative that is likely to impact load growth is the MI Healthy Climate Plan and the goals it aims to achieve.

The MI Healthy Climate Plan was developed pursuant to the issuance of Executive Directive 2020-10 by Governor Gretchen Whitmer. The Executive Directive called for economy-wide carbon neutrality by 2050, and it charged the Michigan Department of Environment, Great Lakes, and Energy with establishing the MI Healthy Climate Plan to identify opportunities to achieve this goal. The precise impact upon the UP is unknown, but the electrification of industry, transportation, home heating and other appliances, and other applications will result in increased electric load. While some portion of this increase can be offset by advancements in energy waste reduction and increased energy efficiency, much of this load increase is likely to remain on the system and will require other solutions. However, the precise size of this load and how long it will take to get to the expected long-term peak demand, is uncertain because electrification is heavily driven by customer uptake and acceptance. Appropriate timing of grid investment to correspond to customer uptake is key. Investing too early results in increased rates to customers unnecessarily while investing too late results in the inability for new load to connect to the system or customers to electrify when they wish. Understanding when and where these loads will appear on the system is vital to knowing what investments are most reasonable and prudent.

Industrial Customer Changes

In addition to potential load growth from consumer choices and public policy, there is the possibility of increased load growth from other large industrial customers that include mining operations and the development of data centers. The UP has been home to mining operations for decades. Recent media reports related to the Eagle nickel mine and proposed copper mining signal the possibility of significant load increases. In addition, as the need for critical minerals and other raw materials continues to increase, there is the possibility that abandoned mines once deemed uneconomical could find new life. Data centers are a new industry experiencing aggressive growth. Data centers may favor the UP given its climate with mild summers because a significant portion of data center load is used for cooling. While there is nothing definitive, discussions with UP utilities suggested that any of these loads have the potential to increase electric demand substantially, particularly in relation to the UP's current energy usage. The average data center uses 10 to 50 times the energy per floor space of a typical commercial office building.[50] Given the UP's current generation resource portfolio and its current UP-wide customer demand, a single data center could increase the load of a given utility substantially.

[50] Data Centers and Servers | Department of Energy

Electric Provider Forecast Challenges

Electrification growth relies on several variables for which there is currently no firm data, which makes predicting future load growth difficult. In conversations with UP utilities, Staff requested information on potential load growth within each utility's service territory and the utilities shared that they do not currently have any information related to projected load changes and they lack clarity around the pace of potential future electrification. For these reasons, they do not expect significant load growth in the foreseeable future. Separately, the MPSC is in the process of completing a statewide electrification potential study which is expected to be completed by August 2025. Once completed, the electrification potential study will give lawmakers and the MPSC greater insight into load growth potential.

Options to Reduce the Carbon Intensity of the Existing Reciprocating Internal Combustion Units, with Particular Focus on How the Unique Geological Conditions Within the Upper Peninsula Influence the Feasibility of Deploying Clean Energy Systems

Hydrogen

A potential option for reducing RICE units' carbon emissions involves the blending of hydrogen gas with natural gas fuel, or even replacing natural gas with hydrogen to power the units. Because burning hydrogen does not release greenhouse gases, electric generation using hydrogen as fuel would qualify as "clean" under PA 235. However, a complete shift to hydrogen-fueled generation would not be necessary to realize a reduction in carbon emissions as blending varying amounts of hydrogen to offset natural gas consumption at the RICE units could result in emissions reductions.

In March 2023, UMERC performed a hydrogen blending demonstration project at the A. J. Mihm RICE generating facility with the Electric Power Research Institute (EPRI).[51] The study looked at replacing a percentage of the normal volume of combusted natural gas fuel for the RICE unit with hydrogen gas without any physical modification to the RICE unit's equipment or mechanisms. A single unit at

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[51] The full report is available only to EPRI members. The Executive summary can be found at https://www.google.com/url?sa=t&source=web&rct=j&opi=89978449&url=https://www.wartsila.com/docs/default-source/energy-docs/technology-products/white-papers/executive_summary_hydrogen_blending_demonstration_wartsila50sg.pdf%3Fsfvrsn%3D99bd3d43_5&ved=2ahUKEwiVvPnsjviJAxVt5ckDHaGxMHoQFnoECBoQAQ&usg=AOvVaw3YKtnqOn0JV0auIgmrPUyn, retrieved 11/25/2024.

the facility was tested at various loading conditions with up to a 25% hydrogen blend. At lower engine loading levels[52] (an electric generation output of 50%), blending of hydrogen into natural gas showed a slight improvement in efficiency. This improvement in efficiency during low engine loading conditions was attributed to a more complete combustion of natural gas with the addition of hydrogen. CO_2 emissions from the blending of hydrogen were reduced but it was not a linear reduction. For example, a 25% hydrogen blend resulted in a CO_2 emissions reduction of approximately 10%. A reduction of NO_x emissions was also observed with the addition of hydrogen at lower loading conditions. At 75% loading level, the efficiency increases seen when adding hydrogen to the fuel mix at lower loading levels were lost and the efficiency was comparable when run on pure natural gas.

At higher hydrogen blending levels and high loading levels, the results were more mixed. There was an increase in NO_x emissions with a 25% hydrogen blend at loading levels of 75% or higher. There seems to be an increase in carbon emissions at maximum loading for higher hydrogen blends as well. The unit was unable to achieve a 100% loading level with a 25% hydrogen blend. The highest level achieved was 95% loading.

These results did illustrate that hydrogen blending is possible but there are challenges that include unit design and compatibility and the availability of hydrogen. If the fuel system was designed around hydrogen or hydrogen blending, the result could be improved at maximum loading. It should be noted that the study was performed under standard operating conditions for natural gas; there was no tuning performed on the RICE units to optimize for burning hydrogen. While blending is technologically feasible, the design of the existing RICE units limits the amount of hydrogen that could be incorporated which impacts the opportunity for emissions reductions. The manufacturer of the RICE units is currently working on a design that would allow for new RICE units to operate using 100% hydrogen, thus making hydrogen blending a viable solution from a compatibility standpoint. However, the availability of hydrogen fuel is not yet widespread.

The availability of hydrogen fuel for the RICE units presents a challenge for two reasons. First, there is no reliable source of hydrogen in the quantities needed to fuel the RICE units with 100% hydrogen because this market does not exist at this time. Second, making and delivering hydrogen in the quantities needed to fuel the units requires the development of significant infrastructure. Hydrogen is just beginning to emerge as a potential fuel source and its future potential is not yet fully understood. However, while the costs associated with hydrogen fuel and the infrastructure necessary to supply it to UMERC's RICE units are currently unknown, it is not unreasonable to presume that such costs could be significant. Therefore, hydrogen may be a viable alternative in the future, but only if these challenges can be overcome.

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[52] Loading levels refers to the load on the RICE unit. A high loading level means that the unit must supply a larger amount of electricity to meet the demand. A low loading level means that the unit can meet demand by generating a lower amount of electricity.

Renewable Natural Gas

Another opportunity to reduce the emissions of the RICE units could be found through the combustion of renewable natural gas (RNG). RNG is a fuel that is produced by capturing methane from organic waste sources such as landfills, wastewater treatment plants, and livestock farms. RNG is retrieved by capturing methane that would otherwise be released into the atmosphere, resulting in a net reduction of greenhouse gas emissions when used as fuel compared to traditional fossil natural gas fuel. In terms of its chemical composition, RNG is similar to fossil natural gas and can be used interchangeably with it. While PA 235 does not explicitly identify RNG in the definition for a Clean Energy System that could be used to comply with Michigan's clean and renewable energy standards, MCL 460.1003 (i),[53] the Commission could consider initiating a rulemaking proceeding or the legislature could amend PA 235 to explicitly include RNG as a clean resource.

If RNG were designated a clean fuel, or even as a renewable energy resource, then another option to reduce the carbon emissions of the RICE units and achieve compliance with the standards in PA 235 would be to power the units with RNG rather than conventional natural gas. The use of RNG would not require additional infrastructure to deliver fuel to existing natural gas-fired generation facilities because it could utilize existing natural gas pipelines. While there are challenges to the deployment of RNG, there is potential for RNG development in Michigan that could support the power industry.

Pursuant to Public Act 87 of 2021, the MPSC commissioned a report into the potential for RNG development in Michigan. As part of that report, two scenarios for Michigan-based RNG production were analyzed examining demand, costs, technological development, and policies that could support RNG project development. The "achievable" production scenario captured 18% of RNG feedstock resources in Michigan while the "feasible" scenario captured 47% of Michigan RNG feedstock resources.[54] Under the "achievable" scenario, Michigan could produce 57.2 tBTu of RNG from 18% of the total feedstock inventoried in the report. In 2023, the two UMERC-owned RICE facilities and the Marquette Energy Center used 7,227,069 MMBtu (7.2 tBTu) worth of natural gas.[55] While the needs of the UP RICE generating facilities could be met under the "achievable" scenario, it is likely that designation of RNG as "clean" or "renewable" would drive up demand for the fuel across all utilities in the state.

While sufficient RNG could be produced in Michigan to support the operation of the RICE units in the UP (provided other utilities are not also attempting to be supplied

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[53] PA 235 of 2023, Section 3, subsection (i)(*iv*) states that clean energy systems are generation facilities that fit one of four criteria, including technologies defined as clean by the Commission as consistent with the purposes of the Act through a rulemaking process.

[54] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 3.

[55] EIA Form 923 2023 early release data.

by those same resources), there are cost challenges. RNG and the environmental attributes that certify it is a clean fuel are sold separately. RNG purchased with environmental attributes is more costly than typical natural gas. Therefore, the use of RNG would increase the cost of operating the RICE units in the UP, which would likely impact customer rates. When the Commission's RNG report was issued, RNG prices ranged from $9.92-$70.86/MMBtu.[56] According to the July 2024 issue of Waste Today Magazine, the average National price for RNG was $15/MMbtu. The Henry Hub natural gas spot price for July 2024 was $2.07/MMBtu. While the price for natural gas is volatile, the highest average monthly spot price for the last five years was $8.81 in August 2022.[57]

Different feedstocks and production methods produce RNG in different price ranges. There are two main methods to produce RNG: anaerobic digestion and thermal gasification. Anaerobic digestion is the breaking down of organic matter feedstock using microorganisms that thrive in anoxic conditions.[58] Thermal gasification is where feedstock goes through a partial oxidation reaction, producing H_2 and CO. These gasses then go through a reaction to produce methane.[59] There are different price ranges based on the feedstock for anaerobic digestion. The lowest cost of these is landfill gas, which has a price range of $9.92-$26.85/MMBtu. Other feedstocks have a higher price range. For example, animal manure has a range of $14.53-$49.17/MMBtu and water resource recovery facilities have a production cost of between $10.90-$70.86/MMBtu.[60]

There are 16 candidate landfills that either flare or do not capture their methane emissions in Michigan. Combined, these landfills produce 12.3 tBTu worth of methane that could be captured and pumped into natural gas pipelines, and thus sold as renewable natural gas.[61] While low-cost RNG production from landfills would produce enough RNG to operate the UP RICE units, the cost increase in procuring certified RNG would be significant.

While RNG faces several challenges to adoption, attempts to address any of them are moot unless RNG is classified as either a renewable or a clean resource. Should that classification occur, a tracking process would need to be implemented, and cost challenges would need to be addressed before it could be a viable solution.

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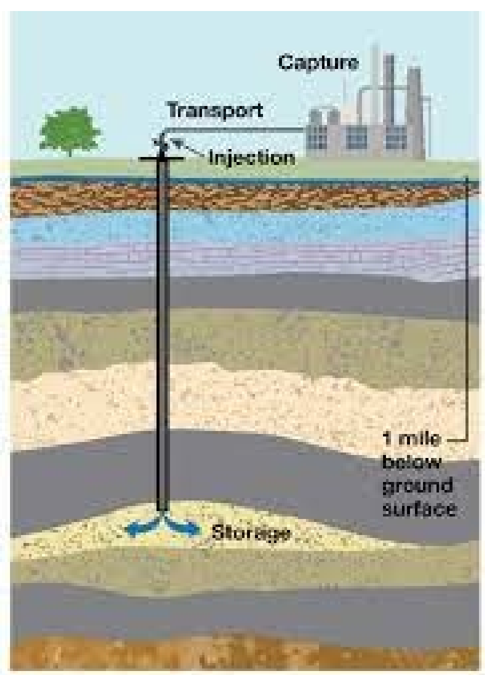
[56] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 6.
[57] EIA Henry Hub Natural Gas Spot Price. https://www.eia.gov/dnav/ng/hist/rngwhhdM.htm
[58] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 18.
[59] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 19.
[60] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 6.
[61] Michigan Renewable Natural Gas Study, September 23, 2022, submitted to the Michigan Public Service Commission, p. 29-31.

Carbon Capture and Sequestration

Carbon Capture and Sequestration (CCS) is referenced in PA 235 as a technology that could be paired with natural gas generation to meet the clean energy criteria if the CCS is sufficiently effective. CCS is a technology whereby the CO_2 from an emissions stream of thermal generation (for instance a coal or natural gas facility) is separated and concentrated then stored permanently so that it cannot enter the atmosphere. This is done geologically, where the CO_2 is injected into rock layers at depths where it cannot escape. Often, the CO_2 must be transported to the geological feature that can accommodate it. This is done using CO_2 pipelines or via truck or rail transportation.

To understand whether CCS is a viable solution for addressing compliance in the UP, Staff investigated the UP's geological potential for sequestration. The Oil, Gas, and Minerals Division at the Michigan Department of Environment, Great Lakes, and Energy (EGLE OGMD) met with Staff to discuss the suitability of the Upper Peninsula for CCS and provided information about the geological requirements for CCS.

Figure 4: Carbon Capture and Sequestration



As a threshold matter, federal requirements state that injection wells must not endanger underground sources of drinking water (USDW). Therefore, if the water at a specific depth is considered drinkable and is connected to either a public water supply or wells that are being used for drinking water, all types of injection, including CO_2, are prohibited. In addition, two geological features must be present in order to effectively store gases geologically. The first is rock with enough porosity to accommodate the injected CO_2, and the second is a layer of impermeable rock that prevents the upward migration of the gases called a continuous confining zone.

While the structures to accommodate the injection of gases exist in both the Lower and Upper Peninsulas, there is a marked difference when considering USDW requirements. In the Lower Peninsula, the water table turns brackish and becomes saline below 300 to 800 ft of depth. However, in the Upper Peninsula, even at a depth of 2000 ft below the surface, there is still drinkable water and, due to the permeability of the rock, the water at this depth is still connected to wells that are used for drinking water.[62]

Explorative tests done by Amaco Production Company drilled down to 6,500 ft below the surface in Alger County (located east of Marquette County) and found no rock formation appropriate for a confining zone. Due to the presence of USDW at extreme depths, and a lack of rock appropriate for a confining zone, the central and eastern portion of the UP are not suitable for CCS. While there has been less exploration of the western portion of the UP, it is unknown if there is a confining zone that would separate the western portion of the UP from the central and eastern UP's drinking water.[63]

Without a feasible underground storage option in the UP, utilizing carbon capture would require transporting CO_2 to sequestration sites in either Wisconsin or the Lower Peninsula. While such transportation is technically possible, the economic feasibility of carbon capture and sequestration is reduced as transportation distances increase.

For these reasons, CCS is likely not technically feasible in the central or eastern UP, may not be technically feasible in the western UP, and faces transportation cost related challenges thereby reducing its suitability as a compliance tool.

Other Information That May Be Relevant to the Development of Strategies to Satisfy the Clean Energy Standard for an Electric Provider Whose Rates are Regulated by the Commission and that Owns and Operates Reciprocating Internal Combustion Engine Units in the Upper Peninsula

Joint MISO/ATC Transmission Study

MPSC Staff has engaged both ATC and MISO to perform a transmission study (the MISO/ATC transmission study) analyzing the effects and feasibility of limiting fossil generation in the UP. The study seeks to understand two key issues. First, assuming that all electric providers meet compliance with the renewable energy standard enacted in PA 235, how much dispatchable generation or what transmission solutions would be needed to maintain system operability within applicable planning standards? Second, are the 2016–2017 UP transmission and generation studies still valid or have the study results changed since the transmission reinforcements have been completed and renewable generation installations increased?

[62] Appendix K, p. 1-3.
[63] Appendix K, p. 3.

The study assumes the UP will achieve the 60% renewable portfolio standard (RPS) by 2035 and the UP portion of the energy storage standard, as required by PA 235. Therefore, the MISO/ATC transmission study assumes that 1) 60.3 MW of battery storage was installed on the UP transmission system, and 2) Renegade, Groveland, and Republic solar all come online at their intended operation dates. Even when these planned renewable energy projects are added, additional renewable generation is needed to meet the 60% RPS. The balance of renewable energy generation needed to meet the 60% RPS requirement is slightly less energy than would be generated by the renewable projects within the UP that are currently being studied in the MISO generation interconnection queue.[64] Therefore, as a proxy for meeting the renewable portfolio standard, the MISO study assumes that all the MISO generation queue renewable projects are built.

Due to time constraints with completing the transmission study and the limited availability of MISO modeling staff, the MISO/ATC transmission study has been tailored to leverage existing data to the extent possible. Given the December 1, 2024, deadline for this report and the time it will take to complete the MISO/ATC transmission study, the final transmission study will be shared with the Legislature when it is received from MISO in early 2025.

Preliminary MISO Study Results

Preliminary results of the MISO transmission study were derived from a steady-state analysis. This means that the system was modeled under one set of operating conditions and those conditions did not change throughout the study, as compared to a dynamic study. Dynamic studies are more labor intensive to model.

Based on the steady-state analysis, MISO has indicated that when all diesel generation is offline, but the UMERC and Marquette RICE units remain online, there are no apparent system concerns. When the same steady-state analysis is done with all diesel and RICE generation offline, there were times of generation redispatch[65] that alleviated many of the system concerns. Additional concerns were alleviated by installing a shunt reactor[66] on the system.

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[64] The MISO Generation Interconnection Queue represents proposed generation projects within MISO. Projects in the queue have been proposed by utilities or developers and are being studied to understand what, if any, transmission system impacts would be expected from the project and to identify subsequent upgrades necessary to facilitate their interconnection with the system. As indicated above, there are currently enough projects in the queue to meet the renewable energy standard applicable to UP load-serving entities. Historically, a significant number of projects that enter the queue are not built. While it is advisable to assume that not all of the proposed projects will be built, these projects do serve as a useful proxy for purposes of the study.

[65] Generation redispatch means that MISO instructs a generator to change its output power to ensure transmission system stability.

[66] A shunt reactor is a device used in high-voltage power transmission systems to control voltage and increase energy efficiency.

While many concerns can be addressed with generation redispatch or through the installation of a shunt reactor, approximately 7% of the modeled system overloads[67] are not able to be mitigated by either of these solutions. These remaining system concerns could only be alleviated with transmission system modifications to ensure that load curtailment would not be necessary. Transmission system modifications could result through either ATC planned projects or included as projects within Tranche 2.2 of MISO's Long Range Transmission Planning (LRTP) process. LRTP is a MISO planning activity focused on "improv[ing] the ability to move electricity across the MISO region from where it is generated to where it is needed - reliably and at the lowest possible cost."[68]

It is important to note that the projects necessary to alleviate the remaining 7% of system overloads are projects that are not currently identified. As indicated by MISO, these system issues could be studied as part of MISO LRTP Tranche 2.2 or through ATC planned projects. Currently ATC does not have planned projects that address these concerns.

ATC planned projects could be developed through either generation projects that are being studied in the generation interconnection queue to determine the system impact of interconnecting the proposed generation or through ATC's transmission planning process. Projects developed through the ATC planning process could result in a significant cost burden to either developers (for generator interconnection projects) or UP customers (for other projects) because they are typically paid by the ATC's local planning zone so costs would largely be allocated to UP customers.

MISO LRTP Tranche 2.2 is not expected to start until 2026 and may take a year or more to complete. Previous MISO LRTP Tranches did not include Michigan's clean energy and renewable energy standards because the studies were already underway when the 2023 energy legislation was passed. MISO LRTP Tranche 2.2 projects are projects that will have been found to have regional benefit. If projects were identified through that process, the costs would be allocated to customers on a regional basis determined by a transmission customer's load share ratio.[69] Transmission projects typically take 4-6 years to build once approved by the MISO Board of Directors.

Given these uncertainties and the system concerns that were not alleviated through existing transmission system ability or expected new projects, further study concerning the system impacts is necessary. Further study should include dynamic studies of the transmission system to better understand impacts to system stability

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[67] System overloads refer to either voltage or thermal overloads that exceed the operational constraints of the system, thereby putting the transmission system equipment at jeopardy.
[68] https://www.misoenergy.org/planning/long-range-transmission-planning/
[69] Load share ratio refers to the load of a specific transmission customer as compared to the total load of the region at a specific time.

as well as loss of load expectation studies to understand how well the UP system is expected to meet the MISO reliability standard of one day in ten years.[70]

Energy Waste Reduction

Energy waste reduction (EWR) programs create opportunities for utilities to save energy by investing in technologies, actions, or equipment that use energy more efficiently thereby reducing their overall load without sacrificing customer comfort. Utility EWR programs, authorized and required by statute, typically include initiatives that encourage customers to utilize programable thermostats, install energy efficient lighting, improve home insulation, upgrade home windows, or replace older appliances or furnaces with new, more efficient models. EWR-related load reductions may help to offset some potential long-term load increases that could result from moves toward electrification technologies by UP customers. Pursuant to Michigan law, utilities may administer their own EWR programs or offer EWR programs through the state administrator who operates these programs on behalf of the participating utilities. Each investor-owned utility is required to offer an EWR program to its customers and, beginning January 1, 2025, municipally owned and cooperative electric utilities are also required to again offer these programs to their customers.[71] Information concerning the energy waste reduction programs and energy savings achieved by investor-owned utilities from 2018-2023 is shared below.

UMERC has achieved between 1.06% and 1.59% savings over the past 5 years. It utilizes Efficiency United, the state plan administrator, to administer its program.[72] UPPCo achieved between 1.34% and 2.5% savings annually over the past 5 years. UPPCo plans to increase its EWR to 1.75% for program years 2024 and beyond.

NSP-W achieved between 0.79% and 1.56% savings over the past 5 years. It utilizes Efficiency United, the state plan administrator, to administer its program.

Prior to 2022, MBLP met its annual EWR targets and used a third-party EWR provider to administer its program. With the passage of Public Act 229 (PA 229) and the reapplication of EWR targets for municipal utilities, MBLP plans to once again use a third-party EWR provider. Given the recent change in application of the EWR requirements, MBLP had not completely developed its future EWR plans at the time of Staff's discussions with the utility.

Wisconsin Public Power Inc. (WPPI) uses a third-party administrator to run the EWR program for its UP members. It is currently achieving 0.08% energy savings

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[70] "MISO one day in ten years" refers to a standard used by the MISO that aims to ensure the transmission grid experiences a loss of load event (outage) no more than one day every ten years.
[71] Public Act 342 of 2016 exempted non-rate regulated utilities from offering EWR programs beginning January 1, 2022. However, Public Act 229 of 2023 reinstated this requirement beginning January 1, 2025.
[72] PA 295 Utility Energy Waste Reduction Programs Implementation, 2019-2023 Annual Reports, [Reports and Studies](), retrieved 11/30/2024.

compared to previous year's sales. With the passage of PA 229, WPPI's members in the UP are considering moving away from a third-party administrator to self-implementation, allowing them to run their own EWR programs to reach their goals or to make compliance payments in lieu of operating a program, as permitted by the statute.

Escanaba administers its own EWR program and has an energy savings of 0.13% annually. It is planning to contract with a third-party to administer the higher standards required by PA 229.

Cloverland administers their program through the Michigan Electric Cooperative Association and achieved 1.21% savings over their previous year's sales in 2021. Cloverland is also subject to the 1.5% required by PA 229 beginning in 2025.

Increased EWR may be part of a potential compliance solution in the UP. PA 229 establishes a target of 1.5% EWR as a minimum for electric utilities, but some utilities set a higher target as EWR is generally viewed as a least-regrets path towards providing reliable service to their customers through customer participation in beneficial EWR programs. However, EWR is not a replacement for retiring generation as it does not provide energy or capacity to serve load. Likewise, EWR cannot provide voltage support for the transmission system. While EWR would not obviate the need for any identified generation or transmission solutions, it could reduce the size, and ultimately the cost, of those solutions to fully or partially offset the need to add additional generation and/or transmission to meet growing energy demand. Indeed, the Commission estimates that on a statewide basis, EWR programs have avoided the need to build two new 1000 MW power plants, at a fraction of the costs needed to construct those facilities.

Staff is currently engaging a third-party consultant to conduct the electrification and EWR potential studies required by PA 235. The EWR potential study should provide visibility into the technical and feasible potential of EWR in the UP. Utilities should be encouraged to develop cost effective EWR programs with special consideration for lower income customers and vulnerable populations within utility service territories.

Demand Response

One tool that can be used to reduce load on the system and preserve system functionality is demand response (DR). DR allows the utility to call upon customers in DR programs to temporarily reduce their usage to alleviate system demand. These programs operate pursuant to Commission approved tariffs and offer benefits to participating customers, typically in the form of a lower rate, in exchange for the customer's willingness to reduce their electric demand by a set amount when called upon by the utility to do so.

DR that is registered at MISO as a resource can be registered such that it can be called upon for meeting different system needs. Some DR is available at any time and bid into the daily market and can also be available for use at the electric provider's discretion. Some DR is registered such that it is available only when there is a system emergency. Utilities may count load served pursuant to a MISO DR tariff as a resource to meet its capacity obligation (capacity requirement) under both the MISO resource adequacy requirements and the Michigan capacity demonstrations pursuant to MCL 460.6w. Because utility demand response programs can be used to reduce demand on the system, utilities can use these programs as a capacity resource which reduces the amount of generation resources necessary to meet their capacity or resource adequacy requirement. DR inherently has limitations to frequent use. Although it can aid in meeting capacity needs to satisfy either State or MISO resource adequacy requirements, it provides only infrequent and short-duration system support and is not a long-term solution in lieu of new generation or upgraded transmission needs.

Several utilities in the Upper Peninsula have DR or industrial interruptible/curtailable load. UPPCo and UMERC cover the largest portion of their capacity requirement through DR. Excluding the Tilden Mine load, UMERC has an additional 15% to 20% of its resource adequacy requirement satisfied by DR, depending on the capacity season. When the non-firm load of the Tilden Mine is included, 60%-71% of UMERC's capacity requirements are satisfied by DR, depending on the capacity season.[73] Most of the DR in UMERC's portfolio comes from industrial load, regardless of whether the Tilden Mine is included.

According to UPPCo's 2019 IRP, approximately 55% of its capacity requirements were served by DR.[74] Even though this was before MISO changed over to a seasonal capacity construct, UPPCo has confirmed that it will still rely heavily on DR to meet MISO capacity requirements. It is largely industrial load that is providing the DR resource, and its load has remained flat. Because of this, its DR portfolio is likely to be similar to what was provided by UPPCo in its 2019 IRP.

While both UPPCo and UMERC are heavily leveraged in terms of DR, albeit most of the DR is emergency use only, the municipal and co-op electric providers have small or even non-existent DR programs. MBPL lacks any DR program but can self-serve its load and has purposefully sized and built its resources to avoid the need for such programs.[75] WPPI has 3.5 MW of DR in the UP and plans to launch a thermostat-based DR program in the coming year. Escanaba does not have a defined DR program; however, if there were to be a transmission emergency, Escanaba would be expected to shed 8.5 MW of load, or approximately 33% of its total load. However, Escanaba's required load shed is similar to UMERC's DR because it is able to be dispatched only under emergency conditions and is in the last phase of the emergency measures taken by MISO to stabilize the transmission system.

In addition to commercial and industrial DR programs, many utilities also offer DR programs for residential customers. While these programs are certainly important in reducing load during peak demand, the load reduction that these programs offer

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[73] Id.
[74] Case No. U-20350 Direct Testimony and Exhibits of Gradon R. Haehnel. Exhibit A-1, p. 121.
[75] Appendix F

can be relatively limited given the pattern of residential customers usage. For instance, many residential DR programs rely on customers who agree to allow the utility to interrupt, or otherwise cycle, their air conditioning unit. In the UP, however, air conditioning load is relatively small compared to other areas of the state because the summer temperatures are cooler than other parts of the state in the summer. This, along with other potentially limiting factors, limits the potential effectiveness of expanding these programs, though such expansion could still demonstrate a benefit.

DR expansion has added limitations, one of which is the implementation of MISO's seasonal capacity construct. The use of the seasonal construct adds complexity, as certain types of DR programs are accredited capacity in certain seasons but not others (for instance, residential DR programs allowing for air conditioner cycling would be accredited for the summer but not for the winter).

Additionally, DR is a capacity-only resource, which means that its primary value is rooted in "providing" electricity during peak demand by reducing demand rather than by generating power and is only required to be available when needed to respond to high demand. By their very nature, DR programs have a limited number of times that they can be called to curtail load and are generally used to provide emergency relief or occasional economic benefit. Not only does DR not provide power, but it also cannot provide voltage support on the transmission system the way that generation or other technologies can. While DR can be used to solve some transmission issues, it is usually confined to addressing those issues that are transient in nature, for instance, addressing temporary increases in demand. While an increase in DR may reduce the cost of any solution that is ultimately chosen, it cannot stand as a solution on its own.

Functional Equivalence

As discussed throughout this report, system reliability and affordability concerns are top of mind when considering the UP energy system, and flexibility may be needed as opportunities to achieve compliance are explored. One such opportunity for incorporating flexibility while achieving the goals of the MI Healthy Climate Plan may be to expand the generating units to which "functional equivalence" for compliance purposes applies. To this end, the Legislature could consider expanding the definition of "clean energy system" to include broader "functional equivalence" language.

The MI Healthy Climate Plan,[76] developed in response to Executive Directive 2020-10,[77] aims for Michigan to achieve 100% economy wide carbon neutrality by 2050,

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[76] The MI Healthy Climate Plan was released in April 2022. https://www.michigan.gov/egle/about/organization/climate-and-energy/mi-healthy-climate-plan

[77] Executive Directive 2020-10 was signed by Governor Gretchen Whitmer on September 23, 2020. https://www.michigan.gov/whitmer/news/state-orders-and-directives/2020/09/23/executive-directive-2020-10

and PA 235 codifies both a renewable energy standard and a clean energy standard designed to help meet this goal. Pursuant to PA 235, electric utilities in Michigan must have a 100% clean energy portfolio by 2040. Under the statute, "clean energy" includes electricity generated without creating greenhouse gas emissions, natural gas generation with various levels of effective carbon capture technology, other technologies the Commission defines as clean through a rulemaking, and

> "an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider [on or before February 27, 2024] and that by 2030 receives approval from the commission for a plan that achieves functional equivalence with the clean energy standard in section 51(1)(b) through reduction of greenhouse gas emissions using carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies."

The term "carbon removal technologies" is not defined by the statute.

A similar provision for electric providers in the UP and more broadly throughout Michigan may provide for flexibility while also aligning with the MI Healthy Climate Plan's goal of economy wide carbon reductions. Electric providers have opportunities to work closely with their customers, especially those that consume significant energy through industrial processes and those with broader industry throughout Michigan, to advance the MI Healthy Climate Plan's economy wide carbon reduction goals in the most reasonable and prudent way possible. UMERC and its customer Cleveland-Cliffs provide a prime example of the potential for collaboration.

In contemplating "functional equivalence" broadly, open-air carbon capture technologies, also known as direct air capture (DAC) could be considered. Interest in the development of these technologies has been increasing. While these technologies are in early development, they are generally costly. However, should these technologies prove successful, and should they become cost competitive, they could help to achieve the overarching goal of economy-wide greenhouse gas emissions reductions by pairing with generation technologies necessary to address system reliability and/or affordability concerns that do not otherwise meet the statutory definition of "clean energy." This pairing could further the goals of the MI Healthy Climate Plan, PA 235, and address both reliability and affordability concerns.

Direct Air Capture entails CO_2 being removed directly from the atmosphere rather than from the waste stream of combustion. Because there is a much lower concentration of CO_2 in the atmosphere than in a waste stream of combustion, it requires more energy and is more expensive to use than CCS.[78] The International

[78] DOE Explains...Direct Air Capture https://www.energy.gov/science/doe-explainsdirect-air-capture.

Energy Agency estimates the current cost of DAC as between $125 to $335 per ton of CO_2 sequestered,[79] whereas CCS on a natural gas-fired power plant has an estimated cost between $75 to $125 per ton of CO_2 captured.[80] However, DAC can be sited on top of geological features that are being used to sequester CO_2 and is not limited to the geology at the location of the CO_2 emitting source. If the CO_2 is tracked properly (similar to the above discussion regarding renewable energy credits and RNG contract tracking), a CO_2 emitting source could be considered CO_2 neutral even if it is not equipped with CCS technology. For instance, a UP utility could establish a DAC at, or close to, a sequestration site in the Lower Peninsula and use the carbon captured at that location to offset the carbon emitted from the UP facility.

Because the UP is unsuitable for carbon management through CCS due to its geology, DAC may be the preferred carbon capture technology to the extent that carbon capture is the most reasonable and prudent option. However, in addition to the referenced cost challenges, allowing for such a scenario would require an amendment by the Legislature or rulemaking by the Commission.

Other Considerations

Renewable Energy

The MI Healthy Climate Plan lays out a pathway to reach 100% carbon neutrality by 2050. As one component of reaching this goal, the 2023 energy laws set Michigan on a path to 100% clean energy including meeting at least 60% of these energy needs with renewable energy resources by 2035.

When identifying opportunities and implementing strategies to achieve this carbon neutral future, it is important to consider what has already been achieved. As mentioned previously, UP utilities have already accomplished much regarding integrating renewable energy resources into their generation portfolios and reducing carbon emissions. Not only do UP utilities produce significant amounts of hydroelectric power, but they have significantly expanded other forms of renewable energy as well. Furthermore, utility-owned, coal-fired generation in the UP has been entirely retired and replaced with natural gas-powered RICE units with significantly lower emissions, as well as increasing wind and solar resources. These retirements in the UP happened years before utilities in the Lower Peninsula are expected to retire their coal-fired generation. According to the U.S. Energy Information Administration (EIA), the coal retirements and additions of renewable generation have resulted in a

[79] Direct Air Capture: A key technology for net zero, https://www.iea.org/reports/direct-air-capture-2022, International Energy Agency, 2022, p. 9.
[80] Technology Readiness and Costs of CCS, https://www.globalccsinstitute.com/resources/publications-reports-research/technology-readiness-and-costs-of-ccs/, Global CCS Institute, 2021, p. 29.

71% decrease in carbon emissions from the UP electric sector between 2013 and 2022.

A number of renewable energy facilities have been installed in the UP and additional renewable energy development undertaken to meet the RPS will further reduce the total carbon emissions from the electric sector.

While renewable resources are important for achieving carbon neutrality, these resources do have some limitations that support a measured approach and are, therefore, only one part of the solution for achieving this goal. One factor which supports a measured approach in adding renewable energy facilities in the UP relates to cost. While renewables are the least expensive form of new generation, there is still a cost to build them, and by law this cost is recovered by utility ratepayers. To the extent that new facilities are not needed to meet current electric demand, for instance, because this demand is being met by another already built resource, costs will increase for customers as they effectively pay for additional, otherwise unneeded, generation facilities.

Technical challenges also support a measured approach to incorporating additional renewables into the UP's energy mix. To better understand the anticipated impacts to the UP's transmission system with the incorporation of significantly higher levels of wind and solar generation, as discussed above, the Commission requested that MISO model these potential impacts to the transmission system as part of the study that is expected in early 2025. The study will assume that all renewable resources currently pending in the MISO interconnection queue for development in the UP are developed by 2040. The results of this study should provide a better understanding of how the 60% renewable energy standard will impact the UP's transmission system and will identify broader transmission system needs.

Biomass

Biomass generation facilities produce electricity by primarily burning wood waste along with small amounts of other waste products. Traditionally many of these facilities incorporate a small amount of tire derived fuel (TDF or scrap tires) into the fuel mix that would otherwise be sent to landfills or improperly disposed of. This small amount of TDF improves the efficiency of the biomass units, which means that the units generate more energy per amount of fuel, thereby resulting in lower carbon emissions per MW of energy produced. Biomass facilities generate dispatchable power and provide support to the transmission system. Biomass generation plays an important role in both ensuring generation diversity and maintaining the environment by providing non-landfill disposal opportunities for forest products waste, lumber industry waste, old railroad ties, and scrap tires. Biomass facilities throughout Michigan, including in the UP, provide stable sources of electric power and industrial processing, often in a carbon neutral way when considering the lifecycle of the fuel source. In addition to the environmental and transmission system benefits, these facilities often provide significant support to their typically more rural communities in the form of high paying jobs, community tax base, and other less formalized community support including, for instance, charitable donations. One such facility is located in L'Anse, Michigan. The L'Anse Warden Electric Company's (LWEC) biomass facility not only allows for non-landfill disposal of wood waste with a small amount of TDF, but it also supplies steam needed for CertainTeed's industrial operations.

While biomass generation has traditionally been considered a renewable generation technology, PA 235 excludes biomass facilities that co-fire TDF from the definition of renewable energy resource, even if the facility uses effective emissions control equipment. The exclusion of facilities that co-fire TDF from the definition of renewable energy resource may have a profound impact on the ability to maintain existing biomass facilities because the reduced efficiency from excluding TDF from the fuel mix has a direct impact on the economics of running the facilities. If biomass facilities are no longer able to co-fire with TDF, they are likely to see an increase in operational costs. There is also a likelihood that if these facilities' generation no longer creates renewable energy credits, the contracts for power that these facilities operate under may not continue or be renewed.

Emissions from biomass facilities are governed by the Industrial, Commercial, and Institutional Boilers and Process Heaters: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources that were established by the EPA to govern hazardous air pollutants from biomass facilities under its jurisdiction. The L'Anse Warden Electric Company's biomass facility in L'Anse is one such facility. The company's biomass boiler has a permitted carbon emissions limit of 0.3 lb/MMBtu.

During the Commission's tour of the UP, Commissioners and Staff visited LWEC's biomass boiler facility and were able to learn more about the impacts of co-firing TDF with the biomass fuel[81] and requested further information on the impact of co-firing TDF on carbon emissions. LWEC provided Staff a technical memo, included as Appendix J, which includes the comparison of operations with and without utilizing TDF. The comparison measures emissions on two days, one week apart, with facility operations occurring under similar load and weather conditions. For purposes of the comparison, the facility used TDF mixed with biomass fuel one day and on another did not use TDF. The data from this comparison shows a 16% reduction in daily average carbon emissions on a lb/MMBtu basis when TDF was used in the fuel mix.

While perhaps counter intuitive, the data demonstrates that the use of TDF with biomass fuel results in lower emissions. TDF has a high Btu content, meaning that it burns much hotter than other fuels as compared to the volume of fuel. The high heat content combined with a reduced sensitivity to temperature and humidity helps to dry the biomass fuel and ensures a more complete combustion, thereby improving efficiency. While TDF lowers emissions and improves efficiency, it is worth noting that there is a limit to the amount of TDF that can be cost-effectively co-fired

[81] TDF is added to the fuel mix in a low percentage in effort to maximize combustion of the wood waste product. During combustion, TDF acts as a drying agent for the wood waste by burning hotter and therefore ensures a complete combustion. Without TDF, more carbon is produced because combustion temperatures are lower, resulting in incomplete combustion.

with biomass. The co-fired blend includes a relatively small amount, approximately 10%, TDF in the fuel mix. Co-firing more than 10% TDF with the biomass fuel can result in increased maintenance in the boiler.

Not only does excluding co-fired TDF from the definition of a renewable energy resource threaten to increase emissions from these facilities, but this change has also already disrupted efforts to dispose of scrap tires. The Michigan Department of Environment, Great Lakes, and Energy (EGLE) works closely with biomass facilities to ensure that tires throughout Michigan are properly disposed of. Many of these tires were made into TDF for use as a fuel at biomass facilities or other industrial heat processes.[82] The abrupt halt to the use of TDF in biomass facilities has resulted in an inability to dispose of millions of tires because other industrial facilities cannot accommodate the increased amount of scrap tires or the transportation costs to move scrap tires to facilities that would be able to accommodate them are too high to make economic sense. While other avenues for disposing of these tires are being explored, including using ground tire powder in road construction, these other options require much more processing and transportation therefore increasing the cost to dispose of scrap tires, costs that are ultimately passed on to consumers. Furthermore, while these other avenues could likely absorb these additional scrap tires eventually, these other avenues are not yet at full volume, leaving many tires undisposed and possibly creating the hazards TDF was developed to help alleviate.

In light of the data and demonstrated early impacts on efforts to dispose of scrap tires, the Legislature could re-evaluate the exclusion of biomass that is co-fired with TDF as a renewable resource or specifically consider it to be a clean resource so long as the facility can demonstrate that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation. Limits as to the amount of co-fired TDF could be considered to ensure that the combustion of biomass results in the lowest possible carbon emissions. Additionally, biomass facilities could be required to demonstrate that the overall lifecycle of the fuel results in net carbon neutrality or net carbon negativity. In the alternative, the Legislature could consider a transition period that would allow biomass facilities to move away from TDF gradually or over a longer period of time than what was provided for under PA 235. This phased in approach would also create the opportunity for EGLE to develop and ramp up alternative disposal options.

New and Emerging Generation Technologies

While not yet widely available at a commercial scale, a number of new generation and capacity technologies are in various stages of development including some technologies that are in the pilot stages while others remain only theoretical.

[82] TDF was developed in response to Part 169, Scrap Tires, of the Natural Resources and Environmental Protection Act, 1994 PA 451, as amended, to eliminate large piles of tires throughout Michigan, including along Great Lakes shorelines.

Long Duration/Multi-Day Energy Storage

Long duration energy storage (LDES) and multi-day energy storage (MDES) technologies are rapidly developing. PA 235 defines LDES as an energy storage system that has the capability of continuously discharging electricity at its full rated capacity for more than 10 hours. Likewise, PA 235 defines MDES systems as having the capability of continuously discharging electricity at its full rated capacity for more than 24 hours.[83] There are four main categories of LDES/MDES technologies: thermal, mechanical, electrochemical, and chemical. Each category of storage technology has strengths and weaknesses and may be better suited for some applications or situations than others.

Thermal Storage

Thermal storage converts energy to heat and stores it until the energy is needed. Most commercial thermal storage technologies are designed for industrial applications. These technologies seek to use electricity to heat a thermal storage medium (i.e., bricks, salt, or crushed rock[84]) when it is inexpensive and then provide steam, heated air, or combined heat and power when discharging. Most of these technologies are through the pilot phase and are currently in commercial demonstration.[85] Opportunities for thermal storage to provide a solution to home heating needs are also being explored.[86]

Chemical Storage

Chemical storage refers to storage technology that puts and pulls electrical power in and out of chemical bonds. Fossil fuels are one of the most common examples of storing energy in a chemical bond. Chemical storage releases energy when the bonds in chemical compounds are broken. Energy is also stored in other chemical forms such as biomass, hydrogen, and methane gases. Energy carrying chemicals can be produced from a variety of sources. Converting energy from those sources into chemical forms creates a high energy density fuel. For instance, hydrogen can be stored as a compressed gas, liquid hydrogen, or inside other materials. Depending upon how it is stored, it can last for a long time in a high energy density form. Chemical storage scientists are working closely with national laboratories to continue developing energy storage options.

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[83] PA 235 of 2023, Section (7), MCL 460.1007.
[84] https://www.technologyreview.com/2024/04/15/1091042/thermal-batteries-heat-energy-storage/, accessed November 9, 2024.
[85] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Thermal Energy Storage Technologies Part 1.
[86] https://www.nrel.gov/news/program/2023/exploring-thermal-energy-storage-solutions-for-energy-efficient-buildings.html, accessed November 9, 2024.

Electrochemical Storage

Electrochemical LDES/MDES stores energy using the same process as lithium-ion batteries and is, therefore, the energy storage technology that is probably most familiar to people and likely to be the first to come to mind when thinking of energy storage. Like lithium-ion batteries, electrochemical battery technologies charge and discharge electricity through chemical reactions in the battery. However, LDES/MDES batteries can use different chemistries than lithium-ion batteries and many new chemistries are being investigated and developed. Electrochemical storage technologies typically raise questions and concerns around thermal runaway. Thermal runaway is a situation where the temperature of the battery increases, causing a chemical reaction in the battery that increases the battery temperature and perpetuates the chemical reaction and, in some cases, causing battery damage or, if the battery is large enough, a fire that is extremely difficult to put out. While thermal runaway is a concern for some electrochemical energy storage technologies, many of the chemistries being explored for LDES/MDES have no risk of thermal runaway.[87]

Most electrochemical energy storage technologies have a discharge duration under 24 hours before needing to recharge (depending on the battery chemistry used), so these technologies are primarily classified as LDES under PA 235. There is one known technology under development that would qualify as MDES because it is designed to operate for 100 hours between full cycles.[88]

Many of these electrochemical technologies have completed behind the meter pilot demonstrations and approximately half are moving into the utility scale pilot phase in the 2025–2026 time frame.[89] Manufacturing challenges are often experienced in the development and rollout of new technologies, and this is true of energy storage technologies as well. Two companies have announced that they will reach a one gigawatt a year production capacity in the 2028-2030 time frame.[90] This means that the maximum capacity that one of these technologies could deploy across the world in a year is one gigawatt of nameplate capacity. The transition to intermittent generation will require significant amounts of energy storage. When the need for energy storage is coupled with the popularity of electrochemical storage technologies, demand for these technologies may quickly outpace production capacity resulting in supply shortages and increased cost.

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[87] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Electrochemical Energy Storage Technologies.
https://www.youtube.com/watch?v=59nfKYVTzwg, retrieved 11/30/2024
[88] Id.
[89] Id.
[90] Id.

Mechanical Storage

Mechanical storage involves storing electrical energy in the form of potential energy or kinetic energy. Kinetic energy is stored in flywheels while potential energy can be stored in compressed gas or in the lifting of weights. Compressed gas is usually stored geologically and traditionally has utilized natural gas fuel to reheat the expanded gas in order to compress it again. Some companies are working to develop a new generation of compressed gas storage that requires neither natural gas to reheat the expanded gas nor geological features in which to store it.[91] In exploring opportunities for the UP, these developments are promising for two reasons. First, the UP does not have geological features that would allow for compressed gas storage so the development of technologies that are not reliant on such features is critical if compressed gas storage is to be a viable option for the UP. Second, this new generation of compressed gas storage seeks to store the heat created by compressing the stored gas and to use it to reheat the expanding gas, making these technologies carbon neutral.[92] Most of the new generation of compressed gas storage technologies would be 8- to 24-hour storage and are in the commercial demonstration phase.[93]

The most commercially advanced form of mechanical energy storage is pumped hydro storage. This technology has been commercially viable for several decades. In a pumped hydro system, water is pumped from a lower reservoir to a higher reservoir when excess electricity is available on the system. The water is stored in the higher reservoir until the energy is needed and then the water is released to run through the turbines, generating electricity, and returns to the lower reservoir. Most pumped hydro facilities were installed in the 1970s, with Michigan's own Ludington Pumped Storage Plant serving as a prime example. Like Ludington, pumped hydro storage is traditionally an open system and requires a significant height difference between the upper and lower reservoir. The number of suitable sites in the U.S. is limited by geography and is further limited by aesthetic, environmental, and permitting considerations. There are companies trying to develop closed loop system sites that either utilize existing infrastructure, such as run of river dams, or use a fluid that has a higher specific gravity than water.[94] Fluids with higher specific gravity than water increase energy production because the fluid creates more pressure at the same height differential thereby increasing power generation when released through the turbine due to the greater force on the turbine blades.

[91] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Mechanical Energy Storage Technologies.
[92] Id.
[93] Id.
[94] Long Duration Energy Storage Council, YouTube, Long Duration Energy Storage 101: All About Mechanical Energy Storage Technologies.

Pumped Underground Hydro Storage

Pumped Underground Storage Hydro (PUSH) is another type of storage with potential application in the UP. PUSH utilizes retired mines to act as a pumped storage solution. Though there has yet to be such a facility commissioned, with the increase of intermittent resources across the globe, there has been increased interest in the technology. The UP has many retired mines that could theoretically be converted to operate in such a fashion. Michigan Technological University and the Keweenaw Energy Transition Lab explored this possibility in a case study using the Mathers mine in Negaunee, Michigan.

The study estimated the volume based on maps of the mine and conversations with former mine workers and determined the anticipated volume and head[95] for the upper and lower reservoirs in such a facility. Assuming that the upper reservoir was a surface pond and the lower reservoir was the deepest part of the Mathers mine, and assuming the reservoirs were charged (i.e., water was pumped into the upper reservoir) and discharged (i.e., water moved through the turbines to the lower reservoir) daily, the low volume estimate allowed for the build out of a 655 MW facility.[96] However, the study concluded that a facility this size in the Mathers mine was not realistic because it would require unreasonable flow rates through the main mining shafts between the upper and lower reservoirs making the mining shafts, not projected mine volume, the limiting factor for PUSH.

Mine volume and shaft limitations are not the only challenges to PUSH. The costs of implementing large volumes of this technology are presently very high, between $1.34 million/MW and $4.85 million/MW.[97] Based on this estimate, the cost to construct 234 MW of PUSH, which equals the combined capacity of the UMERC and MBLP RICE units, would be $313.56 million to $1.14 billion. For comparison, the UMERC RICE units cost $277.2 million.

While LDES/MDES technologies hold promise for addressing the energy challenges of the UP and enabling compliance with the 2023 energy laws, these technologies are in early stages of their development, not yet broadly commercially proven, and/or not yet cost competitive to offer a viable solution in the immediate future.

Small Modular Nuclear Reactors

Small Modular Reactors (SMR) are nuclear reactors that can range in size from 10 MW to 300 MW, whereas traditional nuclear reactor plants vary in size from about

[95] Refers to the volume of fluid stored and vertical height difference between the upper and lower reservoir.
[96] PUSHing for Storage A Case for Repurposing Decommissioned Mines for Pumped Underground Storage Hydro (PUSH) in the United States, p.28.
[97] Id. at 36.

600 MW to 1200 MW.[98] SMRs are prefabricated and produced in an offsite facility and shipped to the site where they will be interconnected to the grid and operated for installation, allowing for potential cost reductions through standardized manufacturing and accelerated construction.[99] SMRs are also expected to be safer and simpler than traditional nuclear reactors because they utilize a standard design and rely on passive physical phenomena to cool the reactor core. This change in reactor core cooling also provides flexibility regarding the location of these reactors because access to large bodies of water for cooling purposes is unnecessary.

Due to their reduced size, it is also expected that SMRs would need to be refueled less frequently than a traditional nuclear reactor[100] which is typically refueled approximately every 18-24 months. The decrease in needed refueling should also provide cost savings compared to traditional nuclear reactors. There are a handful of SMRs that are either operational or under construction in China, Russia, Japan, and Argentina, but most SMRs are in the design and development phase. Holtec, the owner of the Palisades Nuclear Plant in Covert, Michigan, is also currently developing SMRs as well. There are currently 80 different designs from multiple countries being developed for varying niche applications, such as electric power generation, co-generation, district heating, and desalinization.[101]

While SMRs hold promise, including the carbon free nature of the generation and flexibility of facility siting, it is still early in the development of this technology.

Joint Utility Planning

PA 235, Section 4, subsection (a) allows two or more municipally owned electric utilities to jointly file a proposed clean energy plan for the purpose of compliance with the clean energy and renewable energy standards. Allowing for a joint filing facilitates joint planning of resources to the extent that a municipality finds that to be in the interest of its customers. Joint planning may be critical for achieving compliance for smaller utilities because resources are not necessarily perfectly sized for each individual utility's needs for meeting its compliance requirement. Allowing for joint planning may be particularly well suited to the UP given the large number of utilities serving a relatively small customer base, and also because the diversity of generation between utilities may make joint planning efforts mutually advantageous. Joint planning may also allow for increased access to the capital needed to invest in renewable and clean resources as well as energy storage systems. The Legislature should consider expanding the ability for joint clean energy

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[98] European Commission, Small Modular Reactors Explained. https://energy.ec.europa.eu/topics/nuclear-energy/small-modular-reactors/small-modular-reactors-explained_en
[99] International Atomic Energy Agency, What Are Small Modular Reactors (SRMs)? https://www.iaea.org/newscenter/news/what-are-small-modular-reactors-smrs
[100] Id.
[101] Advances in Small Modular Reactor Technology Developments: A Supplement to: IAEA Advanced Reactors Information Systems (ARIS) 2022 edition, p. 2.

planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 100,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to more cost-effectively achieve Michigan's clean energy goals and storage targets. More specifically, this would allow for UP-wide solutions to be considered.

Conclusion and Recommendations

The UP can be viewed as a series of discrete load pockets connected by transmission lines generally running lengthwise across the peninsula. Generation is predominantly sited next to the load it serves. The Commission has engaged MISO and ATC to conduct a forthcoming study which will analyze the effects and feasibility of limiting fossil generation in the UP and provide a better picture of what unique conditions are influencing potential generation and transmission solutions for achieving the Renewable Portfolio Standard and Statewide Energy Storage Target.

As the State of Michigan embarks on its path toward net zero economy-wide and state-wide emissions, it is important to take a holistic view, focusing not just on electric generation and not just the Upper Peninsula, but the state as a whole. The UP has already achieved significant decarbonization milestones that the Lower Peninsula has yet to reach. The retirements of Presque Isle Power Plant and Shiras Steam Plant occurred in 2019. The UP retired its coal units more than a decade before the Lower Peninsula, which currently isn't set to fully retire coal until 2032. Because of this, and the extensive amount of hydro generation already present in the UP, between 2013 and 2022, the UP reduced its electric generation CO_2 emissions by approximately 71%. Renewables will continue to be procured by UP utilities to meet renewable energy standards.

The RICE units operated by UMERC and MBLP played critical roles in achieving the substantial decrease in carbon emissions by enabling the retirement of the UP's coal-fired electric generation units, and in UMERC's case, allowing for the lifting of costly system support resource charges imposed by MISO on PIPP and passed through to UP customers.

The existence of UMERC's RICE units is closely tied to Tilden Mine, as it was through the Tilden Mine Special Contract, approved by the MPSC, that these units came to be. As it stands, there is not anticipated to be any great change in Tilden's demand for the foreseeable future.

There remains a need for generation in the UP to support reliability. MPSC Staff has engaged both ATC and MISO to perform a transmission study analyzing the effects and feasibility of limiting fossil generation in the UP with a focus on finding transmission and generation solutions necessary along with the new generation expected due to the renewable energy standard and the UP portion of the Statewide Energy Storage Target. This study is forthcoming and will be provided to the Legislature once it is completed.

There is a plethora of potential options for further reduction of the UP's energy sector carbon emissions, but the UP faces unique challenges to implementation. Demand-side solutions like DR and EWR offer affordable options for avoiding the need to expand a utility's generation capacity but are not standalone solutions. Generation would still need to be built; these solutions simply reduce the size of that need. Renewable generation, like wind and solar, face their own unique challenges in the UP. The geology of the UP often necessitates costly ballasting of solar panels due to the shallow depth of the topsoil not allowing for anchoring, as is done in the Lower Peninsula. There are emerging technologies, like LDES solutions and SMRs, that may one day be viable options for the UP, but right now they are still in the early stages of development and commercialization. There are also potential options for reducing the carbon emissions of the existing RICE units themselves, but they face their own challenges. It is possible to blend hydrogen gas with natural gas to fuel the RICE units and it may be possible in the future to run them entirely on hydrogen. However, there currently is not an economic or practical way to supply the RICE units with sufficient amounts of hydrogen, much less at a competitive cost. Renewable natural gas may also be a potential solution but is currently limited due to supply and lack of statutory consideration as a clean energy source. Carbon capture and sequestration would avoid the need for such alternative fuel sources, but the geology of the UP is unsuited for sequestration within its geology and transportation would add significant cost. Direct air capture, which could achieve functional equivalence to the statutory standards, may represent a compromise solution, as it need not be sited where the carbon is emitted and can thus be placed over suitable geology for sequestration.

Ultimately, the path forward will require a thoughtful approach and care to ensure the integrity of the UP electric system while addressing the need of UP residents for affordable energy and a sustainable future. To that end, the Commission makes the following observations and recommendations:

- The Commission believes it would be helpful to understand whether the UP can accommodate more EWR than what PA 229 requires. To that end, as part of the implementation of the 2023 energy legislation, a potential study that quantifies the economic/technical/achievable potential of EWR in the UP is underway. Results are expected Q3 of 2025.
- Additional clarity concerning the breadth of technologies that can be considered clean energy systems could help electric providers as they seek to determine the most reasonable and prudent path forward. A clear understanding of the types of technologies that can be considered clean energy systems is necessary to develop a clean energy plan, reducing risk and uncertainty for electric providers. Two possible paths to further define clean energy systems are: 1) for the legislature to further define clean energy systems in statute, and/or 2) for the Commission to embark on a rulemaking process to add technologies that qualify as clean energy systems, consistent with statute. Tire-derived fuels, renewable natural gas, and direct air capture technologies are not expressly identified as clean energy technologies in the law. If either the Legislature or Commission rules resulted in the inclusion of biomass with TDF as part of the fuel source, such

a change should include a demonstration that the amount of carbon removed through the biomass lifecycle exceeds the amount of carbon emitted through electric generation.

- Under PA 235, the limitation on distributed generation resources increased from 1% of a utility's average peak load to 10%. This change is likely to increase interest in opportunities to aggregate distributed generation and other distributed energy resources. At the same time, the issuance of Order 2222 by FERC in September 2020 provides a pathway for aggregated distributed energy resources to participate in wholesale energy markets, potentially providing a cost-effective, distributed approach for customer-owned resources to contribute to maintaining reliability and participating in the energy transition in the UP. In its December 21, 2022 order in Case No. U-21099, the Commission partially lifted the prohibition on the ability of aggregated demand response resources from participating in regional power markets as part of the Commission's ongoing efforts to bolster Michigan's energy capacity. However, the actions taken to date only apply to retail commercial and industrial customers with a minimum enrolled load of 1 megawatt, with the Commission noting that "additional work surrounding customer protections is warranted" before allowing participation by residential and smaller commercial customers. The Legislature should work to enact a statutory framework that provides meaningful consumer protections while providing a pathway for aggregated DERs to participate in the regional wholesale electricity markets, consistent with FERC Order 2222.
- The Legislature should consider expanding the concept of "functional equivalence" to include accelerated economy-wide carbon reduction as a carbon reduction option for power generation by including consideration of carbon reduction in another sector. Considerations of "functional equivalence" should apply to more than just power generation, taking a more holistic view accounting for all sources of carbon emissions. The aim of the MI Healthy Climate Plan is economy-wide emissions reduction, and these efforts could help to offset hard-to-abate emissions in the power sector. In the alternative, the Commission could consider whether the rulemaking authority provided for in PA 235 includes an opportunity to build on the concept of "functional equivalence."
- The Legislature should consider expanding the idea of joint clean energy planning that is described for municipalities in MCL 460.1051(3) to include all electric providers serving under 100,000 customers. Joint planning for smaller electric providers would allow for joint solutions and combined capital investment to facilitate the ability to achieve Michigan's clean energy goals and storage targets in a more economical way. More specifically, this would allow for UP-wide solutions to be considered.

Appendices

Appendix A: Acronyms

ATC: American Transmission Company

CCS: Carbon Capture and Sequestration

CHP: Combined Heat and Power

DAC: Direct Air Capture

DR: Demand Response

EGLE OGMD: Department of Environment, Great Lakes, and Energy's Oil, Gas, and Minerals Division

EIA: U.S. Energy Information Administration

EPA: Environmental Protection Agency

EPRI: Electric Power Research Institute

EWR: Energy Waste Reduction

HVDC: High Voltage Direct Current

LDES: Long Duration Energy Storage

MAE: Michigan Agency for Energy

MBLP: Marquette Board of Light and Power

MCL: Michigan Code of Law

MISO: Midcontinent Independent System Operator

MPSC: Michigan Public Service Commission

MWh: Megawatt Hour

NSP: Northern States Power Company

NWUMS NCA: Northern Wisconsin and Upper Michigan Narrowly Constrained Area

O&M: Operation and Maintenance Cost

PIPP: Presque Isle Power Plant

PPA: Power Purchase Agreement

PUSH: Pumped Underground Storage Hydroelectric

RFP: Request for Proposal

RICE: Reciprocating Internal Combustion Engine

RNG: Renewable Natural Gas

SRM: Small Modular Nuclear Reactors

SSR: System Support Resource

TMSC: Tilden Mine Special Contract

UMERC: Upper Michigan Energy Resources Corporation

UP: Upper Peninsula

UPPCO: Upper Peninsula Power Company

USDW: Underground Sources of Drinking Water

WPPI: Wisconsin Public Power Inc.

Appendix B: Comments from UP Residents

Jed Perry, June 30, 2024:

Dear Commissioners Scripps, Peretick, and Carreon: We are writing on behalf of the United Steelworkers (USW) Local 4974 regarding Case. No. U-21572 to express concern about the impacts of Public Act 235 of 2023 on Cleveland-Cliffs Tilden Mine. The United Steelworkers represent approximately 750 employees at Tilden Mine. We are proud to represent the individuals that mine and process iron ore, which serves as a key ingredient for domestic steelmaking, and our role in the state economy. In part, the iron ore we produce at Tilden Mine supplies Cleveland-Cliffs Dearborn Works steel mill in Dearborn, Michigan, which in turn produces steel for the automotive sector, including in Southeast Michigan. Our members have dual interests in this proceeding. First, it is critical to us that the Tilden Mine, which is the last operating iron ore mine in Michigan, remain competitive. The Tilden Mine provides our employees with good paying, middle-class jobs and supports the economy and communities in which we live. Second, as Upper Peninsula residents, we understand the energy challenges and high electric power costs that face our region. We are deeply concerned that Public Act 235 of 2023 failed to recognize the unique energy landscape of the Upper Peninsula. We believe this legislation should have accounted for the $275 million investment that was made in new natural gas generation in Negaunee and Baraga to benefit Tilden Mine and all UP ratepayers and which recently came online in 2019. We are concerned about the cost implications of meeting new clean energy standards so early in the life of these assets. Moreover, the natural gas plants are extremely efficient. They replaced the old coal-fired Presque Isle Power Plant, already achieving tremendous greenhouse gas reductions of 86% per year. We are supportive of efforts to transition towards cleaner energy standards. However, we believe that should be done with a thoughtful approach and with consideration for the impact it will have on workers, employers and our electric bills. We are deeply concerned that Public Act 235 of 2023 failed to adequately consider the circumstances of the Upper Peninsula. As a result, we urge you to highlight the multiple benefits of the natural gas plants in your report and inform a legislative or regulatory solution that will preserve electric reliability and affordability by allowing their continued operation through the remaining useful life of those generating assets. Thank you for your consideration.

Jo Foley, June 31, 2024:

1) I think the urgency of addressing climate change gets lost in the acronyms and details of each law. Should be emphasized at the beginning of every statement of the law, public hearings, conclusions. We should never forget why we are going through all this. 2) The UP is unique in Michigan, [though] some of that uniqueness is shared with Northern Lower Michigan. It is also shared with northern Wisconsin and northern Minnesota which share shorelines with Lake Superior. Cooperation and

collaboration with our watershed partners could decrease duplication and increase innovation suitable to our climate and topography. 3) Working toward energy independence for each small community and isolated homestead would decrease demands on the grid, decrease the need for miles of electric lines and pipelines, and foster jobs of installation and maintenance in each community. Community energy, not big company energy, is what rural areas need. 4) Energy conservation MUST be emphasized. The quickest way to decrease energy use is to weatherize all buildings, make electricity use visible to each consumer, and incentivize using less; not only of energy but of things in general as each requires energy to produce.

Dan Ruokolainen, August 2, 2024:

All, We would like to thank you for holding the open comment here in Marquette Michigan yesterday July 30, 2024, and allowing us the opportunity to give our thoughts on the new energy bills. Also, we appreciate you all taking the time to tour the Tilden mine to get a better understanding of our perspective and concerns. We hope that the tour was information and helpful in your investigational process. Please feel free to reach to us at Local 4950 anytime. You can call me personally on my cell anytime. The number is [REDACTED].

Tonya Swenor, August 2, 2024:

The Superior Watershed Partnership (SWP supports) Public Act 235, which establishes the new clean energy standard and updates the renewable energy standard. The SWP is a Grantee for the Michigan Energy Assistance Program and the MI Impact program and has assisted over 8,000 U.P. households with utility assistance since 2013. We have conducted over 1,400 home energy assessments, 180 weatherizations and 26 residential solar installations to help our U.P. clients reach energy security. In total, 17% of our households receiving utility assistance have received energy waste reduction services. There is still much work to do. The SWP would like the MPSC to take the following factors into consideration when planning for the energy transition in the U.P.: 1. The U.P. needs more affordable, more sustainable electric rates. 2. In order to move families away from public assistance programs we should focus on making homes energy efficient. 3. The U.P. needs a trained workforce with competitive long-term positions, preferably Yoopers and those transitioning from fossil fuels to clean energy jobs. 4. Many homes need health and safety measures completed before weatherization and/or electrification is feasible. 5. Households who work with social service programs develop long-term trust which can be essential for connection to energy waste reduction services.

Anne Childs, August 5, 2024:

Commissioners: I am writing to comment on Edocket # U-21572. I recently drove 2 hours to attend the hearing held at NMU campus in Marquette, and thank you for your presence there. While I did not comment then, I wish to comment now. I am very distressed that Governor Whitmer would remove the local voice by allowing industrial wind turbines and solar arrays to be built without local consent. This is not government by the people. Michigan's Upper Peninsula is a natural treasure which should be protected for future generations. A unique landscape, and the unique lifestyles of those inhabiting it, should be given greater consideration than, say, an enormous tract of open land in Indiana. The installation of industrial turbines and solar arrays will do irreparable harm to our pristine forests, will jeopardize migratory bird flyways (in the case of the Keweenaw Peninsula), will compromise our tourism industry (which brings significant revenues into our area), and will mar the beauty, quietness, and remoteness that have drawn most, if not all, of the residents of this area. In addition, new roads will damage significant areas and the wind turbines, once defunct and rarely dismantled by the companies who installed them, will remain a forever blot on the spectacular natural beauty of this area. My research shows that wind turbines only make sense to investors because of government subsidies. Investors are often foreign or at least not living in the affected areas, and care little about the ultimate impact on local economies or way of life. The cost of creating these turbines to the decommissioning of these massive machines is astronomical, and the amount of resources consumed in manufacturing them is also rarely considered. I urge you to look beyond the rhetoric and say "no" to industrial wind turbines and solar arrays in Michigan's one-of-a-kind Upper Peninsula. Thank you.

John Childs, August 5, 2024:

Michigan Public Service Commission Case # U21572 I was an attendee at the public meeting in Marquette and voiced some concerns there. I now follow that up with a written response to the topic of the renewable energy developments after the Michigan ruling on land use surfaced. We had spent, over the time of many months throughout 2021-2023, much effort to counter the development of huge wind farms in the U.P. and specifically Houghton and Keweenaw counties. The same had been done earlier in Baraga county. Please give due diligence to the material from those encounters. As residents we do not want to see the damaging visual effects of wind farms nor the social conflicts that arise. Consider the National Park Service written research on “viewscapes” and the example of social conflict that enfolded the Garden Peninsula when turbines were erected there. This is in addition to the pseudo economics that inspires a guy like Warren Buffet to comment that investment wouldn’t even be feasible without government subsidies. --Sounds like public taxes and government (also public) debt going into investor pockets. There is much more rational to oppose the program. Please listen to the variety of approaches. Have the power companies even been challenged to foot the complete bill for wind turbines? Would they, if it is such a profitable enterprise? The whole country is full of this dynamic. The whole scenario develops when higher up game planners create “laws” that press for extreme environmental regulations and then people like you all are forced to push them on the public. These regulations whether it be energy, agricultural, land use, etc. (to say nothing of the now debunked recent medical mandates) ultimately function to fence in the people and herd them like cattle. Let’s make Michigan into a truly progressive community not an oppressive one. Retain local control over localities. Thank you for your considerations.

Janet Curtis, August 5, 2024:

I am concerned about the thought of putting wind turbines in the UP. I believe that it would hurt our economy here in the Keweenaw which depends on tourism. It's our natural beauty here that others come to enjoy and in return help our economy. They only last so long and then where can they be disposed? The current energy here serves our needs and is dependable. Rarely are we without heat and electricity especially during the cold weather. If it's not windy then we'd not have power.

Sandy Karnowski, August 6, 2024:

In the Matter, on the Commission’s Own Motion, to Report on the Unique Conditions Influencing Electric Generation, Transmission, and Demand in Michigan’s Upper Peninsula, to Fully Comply with Public Act 235 of 2023, MPSC Case No. U-21572

- Good evening, Commissioners and Commission staff.
- My name is Ryan Korpela and I serve as General Manager of Cleveland-Cliffs’ Tilden Mine here in Marquette County.
- Cleveland-Cliffs (Cliffs) has been mining in the Upper Peninsula continuously since the founding of our company in 1847. Today, Tilden Mine, together with our LS&I short line railroad, Marquette ore dock and Cliffs’ Technical Group research lab in Ishpeming, employ more than 1000 individuals.
- The workforce at Tilden is represented by the United Steelworkers Local 4974 and USW Local 4950.
- We all look forward to hosting the Commission and staff at Tilden for a tour tomorrow.
- During your tour, I urge you to note the importance of energy to Cleveland-Cliffs’ production of environmentally friendly iron ore pellets. Energy represents approximately 25% of our cost structure.
- Tilden’s peak electricity demand is 180 MW. A majority of that demand is derived from the Tilden pellet plant that employs huge electric motors to grind, concentrate and pelletize iron ore.
- Tilden consumes 1.1 million MWh of electricity each year, or the equivalent needed to power 100,000 homes.

- Beginning in 2013, the Upper Peninsula found itself in an electric power crisis arising from plans to retire the Presque Isle Power Plant (PIPP) in Marquette. Following that announcement, MISO mandated that PIPP must continue operating for reliability purposes and imposed an SSR that cost UP energy customers $6 million per month.
- In the face of this crisis, Cleveland-Cliffs worked in close alignment with the State of Michigan, Wisconsin Electric, the MPSC and other UP stakeholders, arriving at an innovative solution to allow for the retirement of the oversized, coal-fired PIPP, the establishment of clean, right-sized generation in the UP and the termination of the costly SSR. This innovative solution also led to the establishment of UMERC – a Michigan-only jurisdictional utility that put an end to years of cost allocation disputes between the UP and Wisconsin.
- As part of this solution, Tilden Mine entered into a 20-year special contract with UMERC that supported construction of two, natural gas RICE generating facilities in Negaunee and Baraga.
- These new generating plants, brought online in 2019, resolved reliability issues plaguing the UP and enabled the retirement of PIPP, leading to a remarkable 86% estimated reduction in Greenhouse Gas emissions.
- As part of this ongoing study, we urge the Commission to recognize the reality in the UP: that UMERC's RICE units were the perfect solution to a difficult problem; that ratepayers (including Cliffs) have already borne the cost of the new generating assets; and that the GHG-efficient RICE plants are and will remain critical to the reliability and affordability of electric power in the UP.
- Finally, we urge the Commission to recommend a legislative and/or regulatory solution that will allow these RICE units to operate through the remaining useful life of the plants without requiring a costly and duplicative buildout of new generation or the procurement of renewable energy credits.
- We look forward to working with other UP stakeholders, the State of Michigan and the MPSC to ensure that the Michigan's Clean Energy Act achieves its objectives without producing unintended consequences for Tilden and the 1000+ families that rely on our mine for good paying, middle class union jobs.
- Thank you for allowing me to testify. I look forward to answering your questions.

Maddie Manderfield, August 6, 2024:

- Lots of very good points, John. Thank you for taking the time to write them. I hope and pray we make a difference and win this.

Laura Skrumbellos, August 6, 2024:

- I attended the public hearing in Marquette. I heard a lot of college students voice their concerns, mostly about green energy. Most college students don't pay utilities, don't own homes, don't work, want to play and party, and are not responsible for our earth and the knowledge other than what they are brainwashed with in college. They don't know what it is like to feed hungry children, and to protect them from the cold and the dark. The Upper Peninsula is already at their percentage for green, so these endeavors need to go back to southern lower Michigan where they are behind in their quotas for green energy. We have a beautiful and rare place in the UP, and to darken it with wind towers and solar panels is a grave mistake. Tourists come for our unique beauty, not for unsightly industrial projects. Put money back into hydro, and nuclear if anything. The youth don't want clean air as they are huffing and vaping, and screaming clean air. What are they doing in their parent paid homes to obtain clean air? Are they putting solar on their rooftops, wind in their backyards? No, they want government handouts and only see the tourist attractions that do not show the unsightliness and destruction of our beautiful UP. I fought to keep the Groveland Mine Solar project off state land. State land is our land, not the DNR, not the Governor, it is we the people's land. You deem things "brownfields" and then think you can clutter that land up with wind and solar. Keep it off state land. If it is a brownfield, then so be it. It can stay that way. Who is protecting our wildlife, the wolves, the bears, the cougars (that we "don't have", the beavers, the migratory birds, the bats, the salamanders, the endangered species, from encroaching on their homes in these so-called brownfields? You? The Governor? The DNR? Just because college students come to your forums after being coached, and get credit for, does not mean they are the VOICE of the people! You know who is? The ones who worked hard their whole lives to be able to sit back and enjoy the beauty and creation that was God given to enjoy, to protect for their children, and their grandchildren, and for future generations. Which also included these snotty nosed brats who think they know everything and want to change the world instead of protecting it. Take away their cell phones and see how dysfunctional they become. Please keep the UP unblemished and pristine, do not come and take away the very reason we all live here.

Laura Ferris, August 6, 2024:

Thank you for allowing public comments regarding wind turbines. In the first place I don't think the governor should be making decisions to place wind turbines in the U.P. when the people have already said no. In the second place, the U.P. depends a lot on tourism: people coming here to enjoy the out of doors and majestic scenery we have. The atmosphere would be radically changed to have wind turbines dotting the landscape. Also the environment impact of clearing trees, making roads, the impact of migratory birds, and our already faltering bat population, would take a huge toll. Let the U.P. have the chance to vote on the wind turbine issue.

Rene Skrumbellos, August 7, 2024:

[I] attended the public hearing in Marquette, Michigan and I just want to say first off that the board did a fantastic job in a very professional manner. With that being said, a lot of the people who stepped up to the podium talked about clean energy and green energy. How many board members, or the people for the green energy in the Upper Peninsula drive electric vehicles if they are so concerned with clean air? My guess would be none. If you listen to the media or these college students that spoke at the meeting, you would think that the Upper Peninsula is under blackout all of the time, which is not true, except during winter storms and high winds that take trees down over power lines that are not kept cleared. This power that would be created by solar and wind would likely not stay in the Upper Peninsula. These industrial solar and wind projects are too large in size, they need to be toned down and not take up a large footprint. It seems like somebody has stock in solar panels that usually amount to 85% produced in China or a China based company. This is money laundering at its best. Instead of making industrial solar "farms", give incentives to homeowners and business to put it on their roofs. We are at our quota in the Upper Peninsula for green energy. There is no need to put any solar or wind in the Upper Peninsula. Thank you for your time.

Michael Furmanski, August 8, 2024:

I believe that the RICE generators located in the UP are vital to keeping the lights on and everyone involved in this process should be doing everything they possibly can to keep them operational. Additionally, they are great partners for renewable generation due to their fast ramp rate.

Jim Ferris, August 8, 2024:

I am opposed to giving all the decision making power to a small number of people in Lansing when it comes to siting wind and solar generating facilities in the UP. I acknowledge that the state has an interest in sustainable power systems but local people understand the local issues and impacts much better than folks in Lansing. We need to have an equal voice in these decisions.

Chris Swartz, August 8, 2024:

Boozhoo Aaniin, members of the Michigan Public Service Commission, My name is Chris Swartz, and I am writing on behalf of the KBIC NRC who hold treaty rights in what is now known as the state of Michigan. As we discuss these new laws which are proposed to make changes to requirements related to Integrated Resource Plans, establish a clean energy standard, increase the Renewable Energy and Energy Waste Reduction standards, and create a voluntary siting process at the Commission for renewable energy and energy storage projects of statewide significance, it is crucial that we consider the profound impacts these public acts will have on our treaty-protected resources within the ceded territories reserved for Lake Superior bands of Chippewa Indians. Treaty Impact Assessment First and foremost, I urge the Commission to conduct a thorough Treaty Impact Assessment. This assessment should be comprehensive, encompassing the potential impacts on wildlife, air, water, and the ecosystems within our ceded territories. Our treaties are not just historical documents; they are living agreements that guarantee our rights to hunt, fish, and gather on these lands. Any mining project, large-scale utility project, whether it be sulfide or nickel, wind or solar, must be evaluated for its potential to negatively impact these treaty protected rights. Environmental and Cultural Considerations The environmental impacts of these projects cannot be understated. Wind turbines, Nickel mines and solar farms, can have significant adverse effects on ecosystems, local wildlife, including migratory birds, fish and deer populations. These species are not only vital to the ecological balance but are also integral to our cultural and subsistence practices. A comprehensive Treaty Impact Statement will help us understand and mitigate these impacts, ensuring that our treaty-protected resources are preserved for future generations. Co-Management Authority Furthermore, I request the establishment of a co-management authority. This would allow for the adaptation of strategies to monitor and respond to the impacts on treaty resources throughout the ceded territories. By involving Native American tribes in the management and decision-making processes, we can ensure that our traditional ecological knowledge is integrated into the planning and operation of these projects. This collaborative approach will not only protect our treaty rights but also enhance the sustainability and effectiveness of renewable energy initiatives. Support from KBIC Natural Resources Department The Keweenaw Bay Indian Community (KBIC) Natural Resources Department (NRD) has extensive experience in managing and protecting natural resources within the L'Anse, Marquette, and Ontonagon reservations, as well as the western Upper Peninsula of Michigan. The NRD administers programs that include fishery assessments, stream assessments, surface and groundwater monitoring, wildlife and wetland management, and environmental assessments. These programs are guided by a 10-year Integrated Resource Management Plan and the KBIC Strategic Plan. The NRD's work in monitoring metallic mining and exploration activities, as well as their participation in the protection and enhancement of Lake Superior, demonstrates their commitment to preserving the environment and ensuring the health of local ecosystems. Their expertise and resources can be invaluable in conducting thorough Treaty Impact Assessments and implementing co-management strategies. Executive Order 13175 Additionally, I would like to highlight Executive Order 13175, which requires agencies to engage in regular and meaningful consultation with tribes when developing policies that have tribal implications. This order underscores the importance of respecting tribal sovereignty and ensuring that Native American tribes are consulted prior to enacting public acts that may affect their treaty protected rights and resources. The Keweenaw Bay Indian Community expects such consultation to occur when acting with delegated authority from EPA ensuring that our voices are heard and our treaty rights are protected. Conclusion In conclusion, as we move towards a cleaner and more sustainable energy future, it is imperative that we do so in a manner that respects and upholds the treaty rights of Native American communities. By conducting a thorough Treaty Impact Assessment and establishing a co-management authority, we can work together to protect our environment, our culture, and our way of life. We are advocating for responsible and sustainable practices because we have seen firsthand how mining can threaten vital water resources, fish (giigoon), deer (waawaaskashii), and wild rice (manoomin), which are essential to our cultural and environmental heritage. Protecting our water and natural resources ensures that future generations can enjoy a healthy environment. Transitioning to a green economy should not come at the expense of further environmental harm. Instead, we should explore sustainable alternatives that balance economic growth with environmental stewardship and a recognition of tribal inherent sovereignty.

Katherine Moore, August 9, 2024:

Attached, please find the full comments of the Geothermal Exchange Organization.

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003nFQtAAM

Roger Line, August 9, 2024:

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003nxJIAAI

Richard Stasik, August 9, 2024:

https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs000003rO5nAAE

Catherine Andrews, August 12, 2024:

August 9, 2024 Dear Commissioners, Thank you for your recent visit to Marquette for the July 30th Public Hearing regarding the energy legislation that passed last November. I am opposed to any plans to modify or replace the RICE facility in Pelkie. It is working well and when something is working, it doesn't need to be "fixed." I am also opposed to shutting down the L'Anse Warden Electric Company. I and many others in the community worked diligently to get LWEC cleaned up. The EPA became involved when the DEQ failed to protect local residents, and many improvements were implemented to remedy the complaints. I trust the current manager to continue to maintain the safety and integrity of the plant well into the future. As a former L'Anse Township Planning Commission member, and former democrat, I strongly oppose the State takeover of Township siting authority on Industrial Wind, Solar and Battery Storage facility projects. I worked to help collect 987 signatures in Baraga County to get a proposal on the November ballot to rescind this legislation. As you know, our petition drive fell short. However, you need to know that many democrat voters who signed the petition assumed the legislation was written by Republicans. It was incredulous to those on the left that any democrat would be so brazen as to take away our rights to make important decisions on the local level. This is the most tyrannical legislation to be passed in Michigan that I know of. As a result, I and many others, have joined the effort to unseat Jenn Hill as our Representative. As for the meeting in Marquette, I'm sure you saw through the ruse of the coordinated effort by an employee of Circle Power and a couple of others to fill the Public Hearing with college students who are not "Yoopers." It seems plausible that they may have gotten "extra credit" for commenting from the same playbook. It's clear that Renewable Energy is not renewable when one takes into consideration the cost of the necessary complete overhaul of our nation's grid system, the environmental and human cost of extracting critical minerals in countries with oppressive human rights records, the transportation costs of shipping these minerals halfway around the world, and the huge footprint these projects have on the landscape during their brief life cycle. All this expense for an unreliable, intermittent energy source that is destined to destroy the earth to "save" the climate. And to make matters even worse, public-private stakeholders are supporting drastic new electricity demands for EVs and data mining often based upon "emerging" technologies that don't even exist. This makes no sense and JD Vance articulates it better than anyone else. Please proceed with caution.

Kathleen J. Peterson, August 12, 2024:

Dear Sir/M'am, I am writing to share my thoughts re this issue... The U.P. is a beautiful place in the state of MI...it's a pristine area, the jewel of MI actually, that people flock to from downstate MI, Chicago, WI, MN and many other places. I so desire it to STAY the way it is...and it is worth so much to the people who live here to keep that as tourism is such a huge part of our livelihood. Every piece of land should not be messed up by these kind of projects. So because of that we in the Upper Peninsula do not want wind turbines OR acres of solar panels cluttering up our beautiful landscape. Over-all, we believe that all this 'green energy' thinking is wrong to begin with. There are just as many scientific truths against all the climate change issues as there are for them. So, let's not jump into all this without considering all the high cost of proceeding. We don't get enough sunshine in the UP to even have solar panels. We have some on our house and regret getting them as they are not producing as we were told they would. There are also so many issues with wind turbines: the lights that bother people who live by them, what you do when they the blades break down or fall off (a big issue of waste and environmental concern), damage to birds, AND they need fossil fuel to even run the motors that help them turn, plus just the ugliness of them and no one can deny that putting them all over a landscape pretty much destroys the natural beauty of those surroundings. We've even heard that in Marquette, the solar panels used by the power company there don't do much in winter as they are covered with snow and it costs more to remove the snow than the electricity they could make at that time. We would just like people to use some common sense here...people in government who represent 'we the people'...as long as planet earth has existed, there have been cyclical changes in climate and who does man think he is, that he can literally change that. Anything that would be done would be minuscule in the big picture... The financial cost of all these projects to 'we the people' is enormous...with NO guarantee that it will all have been worthwhile in the end. I am not totally against making wise decisions/choices as technology improves...but it really needs to be thought through very clearly and all factors be considered. I'm not against electrical cars, altho I believe a hybrid is way better. BUT I do object to mandates...as a citizens we are guaranteed free choices by our United States and MI constitutions. It's time we get back to that perspective. And in the end, I am totally against these type of decisions being made by a group of UN-elected appointees and taking away our local control!!!!! Thank you for letting me share my point of view...and listening.

Bruce Peterson, August 12, 2024:

Dear Ma'am/Sir, I am quite involved in studying the rights of the people under the United States Constitution, and it does not give the government the right to take the people's land for any reason. Isn't that socialism and communism. In fact, we have an elder neighbor from China, and she tells us nobody over there owns any land; the government owns it all. Most people live in the country, and as I understand it, they are allowed to keep a portion of what they make. But how can they get ahead? it's like they're renting from the government. That is NOT how America was established. Even the PREAMBLE to the Michigan Constitution states, "We, the people of the State of Michigan, grateful to Almighty God FOR THE BLESSINGS OF FREEDOM, and earnestly desiring to secure these blessings UNDIMINISHED to ourselves and our posterity, do ordain and establish this constitution." Both the US and the Michigan Constitutions begin, "We the people." So the government should honor the intent of these documents. I'm passing this letter on to some of my fellow American Patriots here in the UP.

Appendix C: Cleveland-Cliffs Responses to MPSC Staff Questions

Responses to MPSC Staff Questions Letter Dated February 23, 2024 to

Ryan M. Korpela, P.E., General Manager Cleveland-Cliffs, Inc. Michigan Operations

Information regarding the role of the Tilden Mine special contract in facilitating the development of the RICE facilities and information regarding any stipulations of the special contract that would affect potential changes in the operation of those facilities;

a. Role of the Tilden special contract in facilitating the development of the RICE units

- On January 30, 2017, UMERC filed for approval in MPSC Case No. U-18224 of: 1) a certificate of necessity ("CON") to construct the RICE units; 2) certificates of public convenience and necessity ("CPCNs") to construct, own and operate the RICE units; and
3) approval of a special contract dated August 12, 2016 for electric service to the Tilden Mine ("Tilden special contract"). Approval for construction of the RICE units and the Tilden special contract were submitted as a single-package.
- Construction of the RICE units: 1) saved UMERC ratepayers money over a 30-year period as compared to business-as-usual; 2) allowed for the retirement of the costly and aging coal-fired Presque Isle Power Plant ("PIPP") with new clean generation in the UP; 3) avoided $373 million in transmission upgrades that would otherwise have been needed to retire PIPP; 4) enhanced electric reliability in the UP by constructing the RICE units in two different locations; and 5) avoided future system support resource ("SSR") costs in the UP.
- The right-sized RICE units modular design permits capacity adjustments to align with the needs of the UP.
- The construction of the RICE units fulfilled the objective of the Amended and Restated Settlement Agreement approved by the MPSC in Case No. U-17682, which resulted in the creation of UMERC; UMERC was formed to facilitate a long-term generation solution for the UP. The new Michigan-only utility avoided relying on a Wisconsin- based utility for electric power used to serve the UP and avoided multi-state jurisdictional cost allocation issues.
- The Tilden special contract was a critical requirement for the construction of the RICE units, which provided a long-term solution to the UP's energy needs.
- Under the Tilden special contract, Tilden committed to paying: 1) 50% of the RICE units capital costs applicable to Tilden's non-firm planning load level; 2)

100% of the actual RICE units O&M costs; 3) a specified amount of A&G expenses of the RICE units; 4) 100% of the distribution costs for service to Tilden; 5) 100% of the natural gas costs to fuel the RICE units; and 6) a pass-through of ATC, MISO, energy and other charges and credits.

- UMERC testified that the UP generation solution could not be achieved without the Tilden special contract and that Tilden is a critical stakeholder in any long-term UP energy solution.

a. Stipulation of the special contract that would affect potential changes in the operation of those facilities

- The Tilden special contract specifies that UMERC will provide service using RICE electric generation facilities. Section 2.2.1
- The definitions of "Generation Resource" and "Generation Resources" expressly prohibit purchases of Capacity and/or Energy from any sources other than the RICE units, unless agreed to
- UMERC is obligated to provide Tilden with the expected availability of the RICE units prior to the MISO Day Ahead Market close and to notify Tilden of any changes. Sections 2.4.2 and 2.4.3
- UMERC is obligated to offer the full capability and flexibility of the RICE units in the MISO Day-Ahead Market at UMERC's cost of operation consistent with MISO's Tariff and Good Utility Practice. Section 2.4.3.1
- UMERC must also use its discretion to offer the RICE units into MISO's Real-Time Market consistent with MISO's Tariff and Good Utility Practice. Section 2.4.3.1.2
- Pricing under the Tilden special contract is tied specifically to the operation of the RICE units. Section 2.1
- The term of the Tilden special contract runs for 20 years to March 31, 2039. Section 2.0.4

Changes in electric demand, including changes from mining-related economic development projects, that may influence the utilization of the RICE units;

- No anticipated significant electric load changes during the term of the Tilden special contract

Information related to the curtailment provisions in the special contract or UMERC tariff;

- The Tilden special contract is a "Retail Large Curtailable Special Contract"
- Curtailment provisions are contained within Section 2.3 Capacity of the Special Contract and Section 2.6 Buyer's Curtailment Obligations
- The Special Contract is a 100% curtailable contract that can be adjusted by Tilden upon 2 years' prior written notice of the beginning of a MISO Planning

Year, subject to certain conditions Section 2.3.4.2

- [redacted]
- Tilden is subject to curtailment requirements as instructed by MISO, ATC or other reliability authority "under non-emergency conditions related to transmission outages or other bulk system conditions." Section 2.6.3. Economic curtailments are not permitted.

Information about Cleveland-Cliffs' current greenhouse gas emission reduction goals and how these goals and the actions Cleveland-Cliffs has taken to date involving industrial carbonization might inform strategies to be included in the UP Study involving the application of the clean energy standards within the UP energy context; and Cleveland-Cliffs sustainability goals

- o Cleveland-Cliffs set a target to reduce its Scope 1 (direct) and Scope 2 (indirect) greenhouse gas emissions by 25 percent by 2030 on an absolute basis (metric tons per year) compared to 2017 baseline levels. The Company achieved its goal ahead of schedule.
- o Furthermore, Cleveland-Cliffs continued a downward trend of Scope 1 and 2 GHG emissions intensity per ton of crude steel. Cleveland-Cliffs' BF-BOF average emissions intensity was reduced to 1.54 metric tons CO2e per metric ton of crude steel produced (from 1.60 in 2022), a number 28% lower than the 2023 global average of 2.15.
- o Cliffs also maintains a goal to reduce Company-wide energy intensity 10% over 10 years.
- o Cleveland-Cliffs has a target to purchase 2 million MWh of renewable energy annually that is newly developed or additional to the grid

- Projects at Tilden that supported achieving these goals include enabling construction of the RICE units to replace PIPP and reduce Scope 2 emissions, as well as transitioning from use of coal to natural gas at Tilden indurating furnaces that creates cleaner steelmaking feedstock.

- Do not anticipate major electrification projects at this time that would contribute to the UP energy context.

Information about demand response and energy waste reduction (EWR) as it impacts the overall load and demand of the Upper Peninsula.

- Tilden does and will continue to participate in the EWR program, over the last five years Tilden has completed 30 projects that have saved over 18 million kwhs.
- Tilden is a curtailable customer under the Special Contract and a Load Modifying Resource with MISO and does not envision adding additional demand response load in the future.

Appendix D: Escanaba Responses to MPSC Staff Questions

1. What percentage of Escanaba total energy need on a MWh basis is currently met with renewable resource generation? At a high level, how is Escanaba planning to reach the 50% RPS in 2030 and 60% RPS in 2035? What options is Escanaba actively pursuing?

> Historically, Escanaba's existing solar facility provides approximately 1.5% of its total energy, which generates approximately 2000 REC's per year. Based on current loads, it is estimated that Escanaba's 50% RPS requirement will be 65,000 REC's per year and the 60% requirement will be 78,000 REC's per year. Our current Power Purchase Agreement with NextEra does not include renewable energy. At this time, Escanaba is planning to purchase REC's from other utilities to meet the RPS requirements. Escanaba plans to install an additional 2 MW of solar in the next few years, which is estimated to generate an additional 3000 REC's per year. Escanaba will also explore options to buy into future renewable generation projects with other electric utilities.

2. Does Escanaba have any high-level plan for reaching the 80% clean energy standard in 2035 and 100% clean energy standard in 2040? Are there options that the Company is actively pursuing?

> Escanaba's high-level plan is to pursue new Power Purchase Agreements to purchase clean energy to meet the 80% and 100% requirements. Escanaba will also look at options to buy into existing or future clean energy projects.

3. Please describe the current percentage of sales savings that Escanaba achieves through its EWR programs. Does it administer its own programs or rely on a third party to administer programs? What plans does Escanaba have for future compliance and does Escanaba envision increasing the EWR achievement in future years?

> Escanaba currently administers its own EWR program. The calculated 2023 annual savings were 175,772kWh, which is 0.13% of total sales. Escanaba plans to contract with a third party to administer its EWR program to meet compliance requirements for the 2026 calendar year and beyond.

4. How much demand response does Escanaba have in its UP portfolio? In the last 5 years, how many times was the demand response called on to reduce load? How many MWs of load reduction did the demand response resource provide?

> I'm not aware that Escanaba has demand response requirements. We have not had to reduce load for any events in the past 5 years. I understand that UPPCO is the Local Balancing Authority for our area, and they have enough interruptible customers to handle required capacity load shedding events in our area.

5. What are any current restrictions on the interruptible programs? Are there ways in which Escanaba could increase its interruptible programs? What are the limitations to program expansion?

Escanaba does not have an interruptible program. Escanaba does have automatic Underfrequency Loadshedding requirements through ATC and MISO. Escanaba is required to automatically shed 8.3MW or 33% of its load in the case of an underfrequency event.

6. What concerns does Escanaba have regarding resource adequacy should the UMERC and MBLP RICE units be forced to retire or be curtailed?

If the UMERC and MBLP RICE units are retired or curtailed, Escanaba's concern is the overall grid stability for Delta County and the rest of the Upper Peninsula. We purchase nearly 100% of our power from the grid. If generators are removed from the Upper Peninsula, this could potentially lead to grid instability, which could affect all utilities in the Upper Peninsula.

7. Explain any concerns Escanaba has with how the renewable energy standard of clean energy standard will impact customers or UP resource adequacy.

Escanaba's biggest concern is the price we'll have to pay for both Renewable Energy Certificates and for Clean Energy. Escanaba's average annual household income is low. We take pride in our historically low electric rates, which is significant for our low income customers. It is currently unknown how high the cost of REC's will climb and what the cost of clean energy will be. We feel it is very important to allow out of state nuclear power to meet Michigan's Clean Energy requirements.

8. Are there specific UP transmission upgrades that Escanaba would support?

Escanaba is in favor of additional or upgraded transmission lines to supply power to the Upper Peninsula.

9. Does Escanaba have plans to acquire additional generation currently?

Escanaba plans to install 2MW of additional solar generation, which will generate a small portion of its usage and REC's. Other than that, Escanaba has no plans to build generation. We may consider buying into a third-party clean energy generator if the opportunity arises.

10. At a high level, please describe any contracts for capacity or energy, approximately how many ZRCs, etc? When does the contract expire?

Escanaba has a contract with NextEra for energy through 2033 and capacity through 2030. Escanaba's contracted ZRC's are as follows:

• 2024/25 – 25 ZRC's

• 2025/26 – 24 ZRC's

• 2026 through 2030 – 23 ZRC's

11. What load growth has Escanaba seen in the last 10 years? Does Escanaba expect significant load changes in the next 10 years? 20 years?

> Escanaba's load has been declining approximately 1% per year on average for the past 10 years. We've been seeing increased construction in the area this year and planned construction projects in the next few years, all of which is encouraging. Escanaba is expecting a flat or slightly declining load curve for the next 10 to 20 years.

12. Has Escanaba applied for grants for solar generation? Has Escanaba been successfully?

> Escanaba has applied for a Michigan Public Service Commission Renewable Energy and Electrification Infrastructure Enhancement and Development (RE-EIED) Grant to install a solar facility on a brownfield site. Grants will be awarded in the 4th quarter 2024.

13. Does Escanaba have any information that they could share with the MPSC Staff regarding the geological conditions or hurdles regarding the possibility of carbon capture and sequestration in the UP?

> Escanaba has no generation that will require carbon capture or sequestration. We are not familiar with carbon capture technology, so we have no information to provide.

Appendix E: MBLP Responses to MPSC Staff Questions

Questions for Marquette Board of Light and Power

1. What role does MBLP's RICE unit play in its generation portfolio? What is its value to MBLP?

   The Marquette Energy Center (MEC) is the primary piece of our generation portfolio. It is incredibly important to us as it allows us the flexibility to keep our system reliable and our rates competitive. Because of where we are located and our climate, we do not have the same accessibility to the power markets that others across Michigan have. With limited transmission access, limited natural gas capacity, and limited viability of renewable resources we cannot plan for and execute a power supply portfolio in the same way as a utility that is in the lower peninsula of Michigan can. Because of this we rely immensely on the MEC and its unique operating characteristics to give us clean, reliable, and affordable power for our 17,000 customers.

2. Please describe MBLP's recent resource transition and explain the reason MBLP acquired the RICE unit.

   Prior to the installation of the MEC our main resource was the Shiras Steam Plant. The plant was first built in the early 1960's with additional units added to it in the 1970's and early 1980's. The Shiras Plant contained 3 coal fired boilers of which only 1 was still in use as the plant reached its end of life. Prior to closing the Shiras plant supplied over 90% of the power needed for our customers for 50 years.

   Due to the age and operating characteristics of the Shiras Plant it was becoming less reliable and less economic to run. In 2013 we started studying what our next steps should be to maintain a robust power supply with the least impact to our customer base. This study looked wholistically at our needs and all the possible ways we could meet them. The study considered developing new resources (wind, solar, hydro, coal, natural gas, etc.) and purchasing from the energy markets using bilateral agreements with other parties.

   At the time of the study the American Transmission Company (ATC) did not have enough capacity on the transmission system to provide us with Firm service. Being a curtailable load was not acceptable from a reliability perspective so we chose to install a generation resource behind our meter that we could control. The Natural Gas RECIP engines were chosen due to

their efficiency, flexible operating characteristics, multiple generators that operate independently, and the ability to utilize both natural gas and fuel oil as fuel. This combination of attributes was able to give us the level of reliability, affordability, and clean operations that we desired.

Currently we dispatch the RECIP engines into the MISO market economically. Because the machines can start and stop in 5 minutes, we are able to utilize them in a way that shapes our generation to match the economics of the market on an hourly basis. Operating this way has saved our customers millions of dollars since the MEC began operations. Reliability has also been improved as having dual fuel generators behind our meter has kept us from curtailing customer load when the ATC transmission system is not able to supply our needs.

The change in operations from the Shiras Plant to the MEC is also much more environmentally friendly Our emissions output has drastically decreased with Sulfur Dioxide emissions down over 99%, Nitrogen Oxide is down 93%, Carbon Monoxide is down 96%, Carbon Dioxide is down 75% and we are no longer disposing of 17,000 tons of ash in a landfill.

3. Please provide the following characteristics of MBLP's portfolio of resources:
    a. Name of each Unit
    b. Commercial Operation Date
    c. Siting locations
    d. Nameplate capacity
    e. Capacity factor †
    f. Average annual energy production by facility †
    g. MISO seasonal accreditation by facility †
    h. Expected retirement or relicense of each facility †
    i. Total cost†
    j. Planned retirement date prior to passage of PA 235 of 2023

    † Not made public for confidentiality concerns

A	B	C	D	J
Marquette Energy Center	2017	City of Marquette	51 MW	Beyond 2050
Tourist Park Hydro	1920's	City of Marquette	0.75 MW	no plans to retire
Forestville Hydro	1920's	City of Marquette	3.6 MW	no plans to retire
Combustion Turbine	1978	City of Marquette	25 MW	no plans to retire

**** Combustion Turbine is not regularly dispatched**

- **We also have a small community solar garden (155 KW). I did not include this in the table above as it is not large enough to materially affect our system.**

4. Please explain how MBLP is paying for its RICE unit investment. Is it doing so through a bond? When does MBLP expect the RICE unit to be fully paid for?

   The project was paid for with a bond. Anticipated to be fully paid off in 2036

5. Please describe the potential impact to MBLP and its customers should the RICE unit be operationally constrained.

   We are concerned that both reliability and affordability will be impacted if the MEC is operationally constrained.

   Current renewable projects are much more costly than operating the MEC. Transitioning away from how we currently operate will increase our costs substantially. This will also leave us with a stranded investment. The facility was intended to be operational for 40 years or more. To stop using it less than halfway through its useful life would keep us from reaping the economic benefits of owning and operating the plant for its intended lifespan.

   The MEC was constructed in large part because of the reliability it provides. Restricting its operations could have a significant impact on our ability to ensure that reliability. Renewable resources and batteries have not yet developed to a point that they can replace a dispatchable generating facility like the MEC.

6. Does MBLP have plans to acquire additional generation at this time?

- **No**

7. Has MBLP considered the possibility of any type of carbon reduction or carbon elimination technology for its RICE unit's emissions?

   This technology does not exist in a commercially available form. Even if it were available Upper Michigan most likely lacks the proper geology to sequester the carbon in the ground.

8. What would the impact be should MBLP's RICE unit retire prior to its intended retirement date? Are there suitable renewable alternatives to replace the fossil generation? What would the impact be to customers in MBLP's service territory, or the broader UP to the extent that the MBLP generation provides some reliability to the UP beyond the City of Marquette?

- **There are not suitable renewable alternatives to replace the MEC generation. Costs will go up and reliability could go down (see #5 above)**

9. How much demand response does MBLP have in its portfolio? In the last 5 years, how many times was the demand response used? How many MWs of load reduction did the demand response resource provide.

- **We currently do not have any demand response. We intentionally built out our resources in a way that provides enough capacity to supply all our needs along with a reserve margin. This ensures the highest level of reliability for our customers with no concerns that they may have an interruption in service.**

10. Does MBLP think that there is potential for more customer participation in demand response? What is the technical maximum that MBLP could possibly increase its DR portfolio to without compromising reliability for its customers?

- **n/a**

11. Please describe how MBLP complies with its state assigned EWR targets.

We met the prior targets by working with a 3rd party EWR service provider. We will likely take a similar approach in the future. Our plan has not been completely developed yet.

12. How much load growth has MBLP experienced in the past 10 years? Does it expect significant load growth changes in the next 10 years?

- **Our load has not grown in the last 10 years. We are expecting an increase over the next 10 years. How much of an increase will depend on the end use customers behavior, namely adoption of electric vehicles and electrification of the home (heating, appliances).**

13. Do critical facilities within the City of Marquette have back-up generation?

Yes

Appendix F: UMERC Responses to MPSC Staff Questions

Questions Asked by MPSC Staff to UMERC regarding RICE units, DR, and EWR

1. When did UMERC make the decision to retire Presque Isle Power Plant? What was the reason?

   Response:

   WEC Energy Group ("WEC"), via Wisconsin Electric Power Company ("Wisconsin Electric")[1] originally moved to retire PIPP when the Tilden Mine (Cliffs) shifted to an alternative energy provider in 2013. This meant there was not sufficient load to justify the operating costs of the Presque Isle Power Plant and at that time Wisconsin Electric announced the retirement of the Presque Isle Power Plant (PIPP). At that time MISO designated PIPP as a System Support Resource, which resulted in a dispute pertaining to how those costs would be allocated between Michigan and Wisconsin customers (within MISO Zone 2).

   By the time of WEC's acquisition of Integrys, Cliffs agreed to return as a customer as part of the multi-party agreement that resulted in the "Upper Michigan Energy Solution". This agreement was memorialized in the Amended and Restated Settlement Agreement ("ARSA") approved by the Commission in Case U-17682, when it approved WEC's acquisition of Integrys. As part of the ARSA, it was agreed that (1) WEC would develop a Michigan-only jurisdictional utility and seek Commission approval for that utility and (2) that Michigan-only jurisdictional utility would develop modern, clean, flexible gas units that would be built in two locations to serve the mines and UMERC customers, while improving reliability and lowering emissions.

   In June of 2016 WEC filed an application in Case U-18061 seeking authorization to form UMERC and transfer the Michigan-based non-generation assets of Wisconsin Electric and Wisconsin Public Service Corporation to UMERC. On October 19, 2016, a unanimous settlement was reached to resolve all the issues in this proceeding, and the Commission approved that settlement on December 9, 2016. UMERC was formed and began operating effective January 1, 2017. All Michigan-located customers of Wisconsin Electric and Wisconsin Public Service Corporation were transferred to UMERC effective on that date

[1] Wisconsin Electric is currently an affiliate of and was a predecessor Michigan-jurisdictional utility to UMERC.

except the Tilden Mine, which remained a Wisconsin Electric customer until the RICE Units were placed in service.

On January 31, 2017, UMERC filed an application in Case U-18224 seeking approval of Certificates of Need (CONs) to construct the two UP RICE generation facilities and a new special contract between the Tilden mine and UMERC. The new special contract would take effect upon the RICE units being placed in service. On October 25, 2017 the Commission issued an order approving the CONs and the new special contract. The RICE units were constructed and placed in service in May 2019 and at that time the Tilden Mine was transferred to UMERC which provided service under the approved new special contract.

2. Does UMERC see RICE units as a technology that is useful to the situations similar to those in the UP to provide both capacity, energy and transmission support in remote areas or does it view RICE units as more multifunctional?

   Response:

   WEC, including UMERC, sees the RICE Units as a technology that offers an extremely high level flexibility to meet a multitude of needs. These capabilities include providing energy, capacity, transmission support as well as multifunctional capabilities (e.g., serve as spinning reserves, provide inertia to the bulk electric system, etc.). The RICE technology is an ideal technology to "backstop" renewable generation to ensure energy assurance and reliability due to its capability to adjust generation output extremely quickly.

   In WEC's view, the RICE technology's flexibility makes it an appropriate resource for any environment - from a very remote area, such as the UP, to the most densely populated urban areas. In Case U-18224, the Commission concluded that RICE technology was the least cost option to meet the unique power and reliability needs of the UP relative to other resource options, while avoiding the costs of building additional transmission.

3. Does UMERC's holding company have plans to add additional RICE units in its sister utilities outside of Michigan? If plans exist to add additional RICE units, to what purpose are they being added?

   Response:

   Yes, WEC has already added a seven-unit RICE facility at the Weston Generation Campus in Weston, WI. That facility was placed in service in July 2023 and is being used to provide identified capacity and energy needs of the two utilities that jointly own the facility – Wisconsin Electric Power Company and Wisconsin Public Service Corporation – both affiliates of UMERC. The units are currently fueled with natural gas. The units also supply necessary grid stability services.

Wisconsin Electric Power Company filed a CPCN application with the Public Service Commission of Wisconsin on April 5, 2024 to construct a seven-unit RICE facility at the Paris Generation Campus in Paris, WI. That facility is projected to be placed in service in mid-2026 and is being proposed to provide identified capacity and energy needs of Wisconsin Electric Power Company. This facility will be collocated with the Paris Solar generation project which is a 250 MW utility-owned solar project and will be fueled with natural gas. The units are also expected to supply necessary grid stability services.

4. How would UMERC use the RICE units if they were to be operationally constrained in the future?

   Response:

   UMERC's UP RICE units would still serve in their current capacity role, unless operational constraints limited their ability to comply with MISO instructions. MISO's capacity rules reduce the capacity value of resources that are not available (including environmental and / or operational constraints) when MISO needs them.

   UMERC's UP RICE units would also supply energy and grid stability attributes, although at lower levels. Such constrained operation would also, by definition, have the effect of increasing costs of energy supply to Tilden under the Special Contract as well as UMERC's non-mine customers.

5. If the RICE units were operationally constrained, would this have any effect on their seasonal capacity accreditation with MISO?

   Response:

   Yes. Operational constraints will reduce the seasonal capacity accreditation of the resource. MISO's capacity rules, including the recently filed Direct Loss of Load (DLOL) accreditation methodology, will reduce the capacity value of resources that are not available when MISO needs them, as noted in the response to question 4 above. MISO's capacity rules are designed to send a signal that resource unavailability, regardless of the reason, negatively affects the capacity value of that resource.

6. What would be the implications for the Tilden Mine special contract if UMERC were forced to retire the RICE units before the expiration of the contract?

   Response:

   Prior to responding to specific elements of the contract that would likely be impacted, UMERC notes that if the RICE units were required to be retired prior to the expiration of the Tilden Special Contact, the result would be the re-establishment of the conditions that existed prior to the comprehensive Upper Michigan Energy Solution reached as part of the Amended and Restated Settlement Agreement in Case U-17682—which UMERC would like to avoid repeating as that history caused many policymakers to express concerns over reliability throughout the Upper Peninsula. Such a situation would provide significant uncertainty not only to Cliffs but to all UMERC customers with regard to how reliable electric generating capacity, energy, and grid stability services will be supplied to the UP – and at what cost.

The practical implication of the forced retirement of the RICE units would be to eliminate the energy value Tilden receives from the RICE units as a hedge against the cost of energy from the MISO market.

The "Generation Resources Operational Expense" (operation and maintenance cost), the "Energy Charge – Generation" (natural gas cost and MISO market charges), and the "Generation Resources Volume Credit" (MISO LMP payments) would fall to zero.

The remaining provisions of the contract would remain intact, including Tilden's ability to terminate the contract with 60 days written notice and the payment of the liquidated damages outlined in the contract for such termination. If Tilden were to execute that provision of the contract in such a scenario, the result would be that the remaining costs Tilden would be scheduled to pay under the Special Contract would no longer apply and the costs would be recovered from UMERC's non-mine customers.

7. Has UMERC considered the possibility of carbon capture and sequestration, or other carbon reduction or elimination technologies, for its RICE units?

   Response:

   UMERC has not considered these potential options at this time due to the significant costs associated with those options given the current state of advancement and availability of those technologies.

8. Does UMERC know if there is suitable geology to store CO_2 underground within or nearby its service territory?

   Response:

   No. While UMERC is not aware of any suitable geology to store CO_2 underground in the UP at this time, we have not studied that. While the lower peninsula of Michigan is known to have such storage capacity, it would require significant costs to transport sequestered CO_2 to a location in the lower peninsula (or elsewhere) where there is known geology that could be used for its storage. Such costs would include either the construction or repurposing an existing pipeline, plus the costs to maintain that pipeline or to deliver the sequestered carbon via tanker truck.

9. Would UMERC consider the use of direct air capture? Would that be economically feasible?

   Response:

   Yes, but direct air capture technology is in early stage trials. A point source capture (from the plant stacks themselves) would be the most likely scenario to deploy this technology. That said, besides the cost of capturing the CO_2, as noted in UMERC's response to question 8 above, there are uncertainties regarding where to store it, how to get it there, and how much that will cost.

10. Would UMERC be willing to provide the results of the pilot it conducted for the use of hydrogen in its RICE units that it performed in partnership with EPRI?

    Response:

    The detailed technical report is only available to EPRI members and cannot be forwarded to non-members. UMERC was able to obtain and receive permission to share the executive summary of the report, which has been attached to these responses.

11. What concerns does UMERC have for fuel availability if the RICE units were converted to 100% Hydrogen?

    Response:

    At the present time, UMERC would have significant concerns regarding fuel availability if the RICE units were converted to 100% Hydrogen. There is currently not a meaningful market for hydrogen to be used in the quantity need to fuel the RICE units exclusively on Hydrogen making the availability and cost of that fuel a noteworthy concern. Additionally, and similar to the infrastructure needed for the transportation of sequestered carbon, the costs that would be required for the construction or repurposing of an existing pipeline are unknown, plus the costs to maintain that pipeline or to deliver the hydrogen via tanker truck and store it on site. Such concerns may be addressed in the future if a market for Hydrogen develops that provides for its availability at an economical level.

12. Is there a blended percentage of hydrogen with natural gas where UMERC would have similar fuel availability concerns as it currently does with natural gas?

    Response:

Please see UMERC's response to question 11 above.

13. What concerns does UMERC have for fuel availability for natural gas?

    Response:

    NOTE: Portions of this response contain information deemed confidential – all such information is shaded in grey within UMERC's response.

    UMERC has contracted for [******]dth/day of firm transportation service from the [*****] interstate pipeline (until [****]). This pipelin789ijkl.e service allows for access to procure supply from a supply basin with sufficient liquidity of supply at regionally competitive prices. There have not been any recurring fuel availability issues during the first 5 years of the RICE units operations. UMERC also does not foresee any fuel availability issues for its current level of firm transportation service in the future.

    While UMERC commonly arranges for a volume of fuel delivery [****] its firm rights, that volume [******] its firm rights is considered [****], and subject to reliability constraints. Given that the [*****] pipeline does not currently have any [******] deliverability capabilities on this part of their system, UMERCs only concern is a [****] in the [*****] for volumes over its [******] rights.

14. If UMERC decided to retire the RICE units, what zero carbon emissions options would it consider to maintain resource adequacy under the current MISO capacity construct?

    Response:

    UMERC believes that the RICE units remain the best resource to provide the UP with the capacity, energy and grid stability services needed to ensure reliability in the UP. Absent a legislative or regulatory directive to retire the RICE units, UMERC has no such plans

    If UMERC were provided such a directive, it would have to rely on a combination of new generation and new transmission to provide service to its customers in the Upper Peninsula. UMERC would need to procure or construct significant over-capacity of renewable generation (wind and / or solar) paired with lithium-ion storage - enough to weather a multi-day event without recharging. Alternatively, the Company could build gas plants in Wisconsin and use such capacity for the UP, if additional transmission facilities were constructed to allow for the delivery of that energy to the UP. Either of these options would come with significant incremental costs to UMERC's customers (both Tilden and non-mine customers) as well as those of other utilities in the UP and would be inconsistent with the MPSC approval of the Amended and Restated Settlement Agreement in the Integrys acquisition in Case U-17682 as well as the MPSC's resulting approval of UMERC;s formation (Case U-18061) and the CON authorizing the construction of the RICE Units and the Approval of the Tilden Special Contract (Case U-18224).

15. If UMERC decided to retire the RICE units, what would UMERC consider to maintain grid synchronization?

    Response:

    ATC and MISO are better positioned to provide a response to this question. UMERC expects that additional transmission line infrastructure and technologies such as Static VAr Compensators (SVC), synchronous condensers, Flexible Alternating Current Transmission System (FACTS), and other power-electronic based devices are potential candidates. All such options though, would require imposing additional costs on UMERC customers (Tilden and non-mine customers) as well as the customers of other UP utilities.

16. What Percentage of EWR has UMERC been able to achieve?

    Response:

    UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

17. Does UMERC know what percentage of EWR is technically feasible and for how long if the Tilden Mine load is excluded?

    Response:

    UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

18. Does UMERC know what percentage of EWR is technically feasible and for how long if the Tilden Mine load is included?

    Response:

    UMERC has not studied this issue because its EWR (energy waste reduction), or energy efficiency, program is performed by Efficiency United, the Michigan sanctioned administrator.

19. Has UMERC done any forecasting of electrification in its service territory?

    Response:

UMERC has not forecasted electrification in its service territory.

20. How much DR does UMERC use towards its PRMR with MISO for each of the capacity seasons?

Response:

DR Capacity Accreditation including Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	180.4	192.9	201.1	208.7
PY24	183.7	190.2	203.5	212.2

DR Capacity Accreditation excluding Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	19.6	20.2	22.5	22
PY24	20	18.9	24	22

As shown the data above, the vast majority of this demand response is the non-firm load of the Tilden mine.

21. What percentage of its resource adequacy requirement from MISO is fulfilled with DR for each of the capacity seasons?

Response:

%DR/PRMR including Tilden	***Summer***	***Fall***	***Winter***	***Spring***
PY23	63.2%	67%	60.8%	70.5%
PY24	66.8%	69.5%	66.5%	70.3%

%DR/PRMR Excluding Tilden	Summer	Fall	Winter	Spring
PY23	15.7%	17.5%	14.8%	20.1%
PY24	18%	18.5%	19%	19.7%

22. Could UMERC theoretically increase its amount of DR? Is this practically feasible?

    Response: The amount of DR is dependent upon customer eligibility and customers choosing an applicable tariff rate. Not all customers are eligible. The applicable tariffs are:

    - General Primary Full Requirements Service Curtailable Rate Cp3 – WEPCo Rate Zone
    - Large Commercial & Industrial Service – Interruptible Rider Cp-I – WPSC Rate Zone
    - Tilden Special Contract

    UMERC's largest customer is already participating in DR to its maximum capability and would unlikely be able to increase its DR without significant investment. While there may be other eligible customers, the available rate options have been in existence for many years and have attracted little interest from customers, presumably because they do not have operations that would lend themselves to prolonged demand curtailment, or are otherwise not interested in participating in DR.

23. Are there issues with increasing the amount of DR that UMERC counts towards its resource requirement?

    Response:

    See UMERC's response to question 22 above. In addition, the DR's capacity accreditation depends on historical availability of the interruptible/curtailable demand. Furthermore, MISO occasionally commits the UMERC RICE engines to operate around the clock for multiple days on end to support transmission system maintenance outages. In these instances, the engines may be providing voltage support or injecting energy at specific locations to prevent transmission line overloads or both.

    DR is unable to provide a similar level of dynamic voltage support and is unlikely to replace the impact of RICE generation energy injection. DR is generally unable to provide load reduction for days on end. Previous experience with DR suggests that calling for lengthy load curtailments often leads to customers withdrawing from these programs. Thus, DR should be considered a short-term and transitory reliability solution rather than a long term one.

24. What limitations does UMERC have on the use of its DR? For example, is it limited to MISO emergency use only? Or a certain number of events per calendar year?

Response:

The limitations on UMERC's ability to call upon DR are defined in its tariffs and in its MPSC approved special contract and are summarized below:

<u>General Primary Full Requirements Service Curtailable Rate Cp3 – WEPCo Rate Zone</u>
- Available 0800-2200 EPT Everyday
- Max duration = 8 hours, 300 hours/year

<u>Large Commercial & Industrial Service – Interruptible Rider Cp-I – WPSC Rate Zone</u>
- Available 1000-2000 EPT Monday-Friday October – May
- Available 1000-2300 EPT Monday-Friday June- September
- No single event limit. 600 Hour Limit per year
- Emergency and Economic events

<u>Tilden Special Contract</u>
- Available 0000-2400 EPT Everyday

25. Does UMERC have expectations of load changes over the next 20 years? Please describe them.

Response:

Not at this time, although we note that the cooler temperatures and availability of water in the UP are situations that could make the UP a potential location for data center operations.

26. Has UMERC conducted any modeling of the UP system with a replacement technology for the RICE units? If so, can UMERC summarize its results?

Response:

UMERC has not performed modeling of the UP system with a replacement technology for the RICE units; however, as noted in UMERC's response to question 14 above, there are essentially two options that could be pursued to supply the UP with the necessary capacity and energy. First, UMERC could procure or construct significant over-capacity of renewable generation (wind and / or solar) paired with lithium-ion storage to replace the capabilities of the RICE units. The second option would entail the construction of significant transmission facilities to deliver energy and capacity to the UP. However, both options would increase costs to customers in the UP and a transmission build out would not likely supply necessary grid stability services, such as voltage support.

Appendix G: UPPCo Responses to MPSC Staff Questions

Questions for UPPCo

1. Once UPPCo has ownership, or has contracted for, the renewable resources that were the results of the settlement in the Company's last approved IRP, what percentage RPS will the Company have?
    a. Approximately 55%
2. Does UPPCo foresee issues with meeting the 2030 or 2035 Renewable Energy Standard?
    a. Potential issues include:
        i. Construction/supply chain/equipment delays
        ii. Renewable project siting approval
        iii. Changes in retail load causing additional resources to be needed to meet the 2030/2035 RES.
3. Does UPPCo foresee issues with meeting the 2035 or 2040 clean energy standard? What, if any, concerns does UPPCo foresee with meeting the 2035 and 2040 clean energy standard?
    a. Potential issues include:
        i. Limited clean energy resource options that are suitable for a company of UPPCO's size to implement.
        ii. Availability of sufficient renewable/clean capacity within the U.P.
4. Does UPPCo anticipate filing a resource plan and associated analysis for meeting the 2035 and 2040 clean energy standard in its next IRP application?
    a. Yes.
5. Does UPPCo plan on pursuing the relicensing of its existing hydroelectric facilities? If the Company does not have a definitive response at this time, does the Company plan to analyze relicensing of these facilities as part of its next IRP filing?
    a. Yes.
6. What Percentage of EWR has UPPCo been able to achieve annually in the past 5 years?
    a. 1.5%-1.75% deemed savings.
7. Does UPPCo expect to maintain, increase, or decrease its EWR throughout the next 15 years?
    a. Maintain and perhaps increase, dependent upon the incremental cost of energy savings.
8. Has UPPCo done any forecasting of electrification in its service territory? If so, can the results be made available to Staff?
    a. Preliminary. UPPCO intends to present additional analysis in its upcoming IRP.

9. Does UPPCo believe it could theoretically increase its amount of DR? Why or why not?
    a. Perhaps, by a small amount. UPPCO's capacity portfolio is already heavily based upon industrial customer demand response. There is little/no opportunity for additional industrial level demand response. Similarly, there is significantly less electric air/space conditioning load throughout UPPCO's residential customers, and therefore current opportunities are limited. UPPCO is evaluating the potential for additional residential class demand response programs that may present themselves throughout the deployment of beneficial electrification measures.
10. Are there issues with increasing the amount of DR that UPPCo counts towards its resource requirement?
    a. Yes. As noted previously, UPPCO already relies upon a significant amount of demand response to meet its capacity obligations. With increased DR, if it were even attainable, there may be performance issues when the demand response resource is called upon in real time.
11. What limitations does UPPCo have on the use of its DR? For example, is it limited to MISO emergency use only? Or a certain number of events per calendar year?
    a. It is limited to a certain number of events per year, as detailed by UPPCO's CP-I tariff, and RTMP tariff.
12. Does UPPCo have expectations of load changes over the next 20 years? Please describe them. How does the Company anticipate this affecting EWR and DR opportunities, REP requirements, and ability to meeting the clean energy standard?
    a. Generally speaking UPPCO does not anticipate significant changes in its native load over time. UPPCO is evaluating the effects of electrification on both energy and demand requirements that would be experienced by the Company under several assumed electrification adoption scenarios.
13. Did UPPCo retire the Gladstone generating unit in 2022 as planned in its most recent IRP, Case No. U-20350? If yes, what replaced it?
    a. UPPCO has not retired the Gladstone facility.
14. If UPPCo did not retire the Gladstone unit in 2022. what are the Company's future plans for the unit and what was the reason for the delay?
    a. UPPCO will identify an updated retirement assumption for Gladstone in it's upcoming IRP. In short, until UPPCO is able to replace the capacity accredited to UPPCO by the Gladstone facility in an economic way, UPPCO will continue to offer it into the MISO market as an emergency-only resource.
15. What role, if any, do the RICE units located outside of UPPCo's service territory in the UP play in UPPCo's system reliability? Or UPPCo's system generally?

a. The RICE units are interconnected directly to the Transmission system (ATC), and therefore do not directly support UPPCO's distribution system. RSG charges applied through market settlement (per the MISO tariff) compensate these (and any other) unit for operation that is to the benefit of the bulk electric system.

16. Please describe, in as much detail without breaking confidentiality, the difficulties in resource procurement that UPPCO has experienced since its last IRP.
    a. As noted in its IRP annual reports in Case U-20350, the primary difficulty in procuring additional renewable resources has been primarily attributed to siting/special use/land use permitting from the local units of government.

Appendix H: MISO Michigan Phase II Study

* Includes internal appendix

I. Executive Summary

On August 17, 2016, Michigan's Governor Rick Snyder and the Michigan Agency for Energy (MAE) requested the Midcontinent Independent System Operator (MISO) to conduct a near and long term regional evaluation of potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint, specifically Michigan's eastern Upper Peninsula (part of Zone 2) up to Sault Ste. Marie, Ontario and northern Lower Peninsula (Zone 7) at the Straits of Mackinac down to the northernmost portion of the existing 345 kV transmission line near Gaylord, MI. Further, MAE was interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern Lower Michigan could have on the bulk electric system (BES), especially in conjunction with the transmission upgrades. MAE requested MISO to model the production cost savings, reliability, resource adequacy, and power flows that would result from a natural gas-fired generating station located in the northcentral Lower Peninsula of Michigan1.

This Michigan Exploratory Transmission Study, which is Phase II of Michigan's request, consisted of a 2021, 2026, and 2031 fact-finding exploratory analysis of potential generation and transmission additions in Michigan using PROMOD software. Additionally, a powerflow analysis was performed using PSSE software to identify reliability concerns addressed by or caused by generation and transmission additions. PROMOD is a market simulation tool that analyzes the transmission system for every hour in a defined year. PROMOD outputs include Adjusted Production Costs (APC) and Load Costs. PROMOD was used to determine the APC savings with the addition of transmission and generation siting. The MISO Transmission Expansion Plan (MTEP) 2017 PROMOD and powerflow models were used as a starting point and incorporated base model updates, future assumptions updates, and sensitivities identified by Michigan.

Sixteen transmission ideas were analyzed during the study. These transmission ideas ranged from utilizing and upgrading existing electrical infrastructure to large transmission buildouts. As there are no current transmission connections between Ontario and Michigan's Upper Peninsula, all of the transmission options included a new tie line between the two regions. MISO coordinated with Canada's Independent Electricity System Operator (IESO) for connections to the transmission system in Ontario. In addition to transmission, generators sited in Michigan's Kalkaska County and Chippewa County were also studied.

Reliability analysis, coordinated with IESO, identified limitations to the amount of power that could be reasonably transferred between Ontario and Michigan without causing significant reliability issues necessitating costly upgrades to the existing transmission system. A transfer capability level of 125 MW was set as the maximum due to significant and widespread reliability issues identified at higher transfer capability levels. Additionally, for a transmission line connecting Ontario and Michigan, a flow control device would be required to control flows due to significant phase angle differences. Phase Angle Regulators (PARs) are currently

[1] See Appendix A, Letter to MISO from MAE dated August 17, 2016

installed on the Ontario/Michigan tie lines in the Lower Peninsula to help control flows caused by these angle differences. Alternatively, an existing combined cycle unit in Sault Ste. Marie, Ontario could be isolated from the IESO system and connected radially to the Upper Peninsula (Sault Ste. Marie, MI) which would not require a flow control device. This was one of the options analyzed during the study.

The economic analysis determined that all of the transmission and generation solutions did not provide enough economic benefit to cover costs. Due to significant and widespread reliability issues identified at higher transfer limitations (greater than 125 MW) and relatively high costs, the amount of economic potential was limited. Generation and transmission in the Upper Peninsula provided comparable amounts of economic benefits for similar costs.

II. Introduction and Background

On August 9, 2016, MAE and the Michigan Public Service Commission (MPSC) requested MISO to conduct a study to help Michigan better understand the effects of declining reserve margins and the impact of several retiring coal plants, particularly during high load emergency conditions. Specifically, they requested that MISO assess and inform Michigan of vulnerabilities associated with planned or unplanned outages at the Palisades and Fermi 2 nuclear power plants in 2018, while at the same time experiencing very hot weather similar to that experienced in the summer of 2012 when both nuclear plants were down during a hot weather alert.[2] MISO performed a study (Phase I) to address MAE's and MPSC's request.

Phase I determined that under high demand conditions in 2018, demand response programs planned by Michigan load-serving entities as outlined in recent MPSC filings, as well as building additional peaking capacity, would be necessary to meet reserve margins. The demand response programs become increasingly important when the system is stressed due to high demand and/or unexpected plant outages. In addition to implementing demand response programs, 400 MW of additional peaking capacity should be considered in the near term. The need for peaking capacity could be delayed by further increasing demand response in Michigan.

As a supplement to the first request, Governor Snyder and MAE requested MISO to conduct a study of near and long term transmission expansion options to better connect the Upper Peninsula of Michigan to the Province of Ontario as well as to the Lower Peninsula of Michigan on August 17, 2016. The study would examine potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint. Further, MAE was interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern Lower Michigan could have on the BES, especially in conjunction with the transmission upgrades.[3] Assumptions and results of the Phase I of the study were used as inputs into Phase II.

[2] See Appendix B, Letter to MISO from MAE and MPSC dated August 9, 2016

[3] See Appendix A, Letter to MISO from MAE dated August 17, 2016

Model Development and Assumptions

The base models and assumptions for this study started with the MTEP17 powerflow and PROMOD models using the Existing Fleet future assumptions. Michigan staff reviewed and worked with MISO staff to provide updates to the base models. The study focused on the Michigan footprint, with the IESO footprint modeled to study increased imports from Canada. After the base models were constructed, incremental models were created to include proposed transmission and generation ideas.

1) Local Resource Zones

Michigan is located in two of MISO's Local Resource Zones (LRZ): LRZ 2 and LRZ 7 (Figure 1). Michigan also has a very small amount of load in MISO Zone 1 in the western Upper Peninsula, which has been excluded from this study. Michigan's Upper Peninsula is in LRZ 2, which includes Local Balancing Authorities Michigan Upper Peninsula and Upper Peninsula Power Company. LRZ 7 Local Balancing Authorities include Consumers Energy – METC and Detroit Edison Company. Based on a load ratio share of energy, about 3% of Michigan's load is in LRZ 2, about 97% is in LRZ 7, and less than 1% is in LRZ 1.

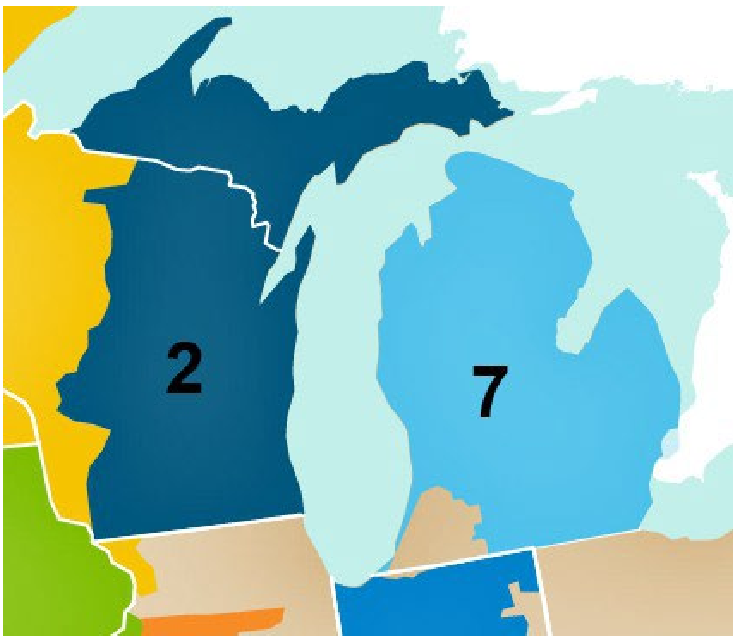


Figure 1: Michigan in Local Resource Zones 2 and 7

2) Natural Gas Price Forecast

The natural gas price forecast of the study base model – the MTEP17 Existing Fleet future – was developed with stakeholder input during the MTEP17 futures development process. This forecast is derived from NYMEX spot prices for years 2016-2017 and the average of Energy Information Administration and Wood MacKenzie forecasts for years 2018-2035. The natural gas price forecast for Michigan generators for the study period is below (Figure 2).

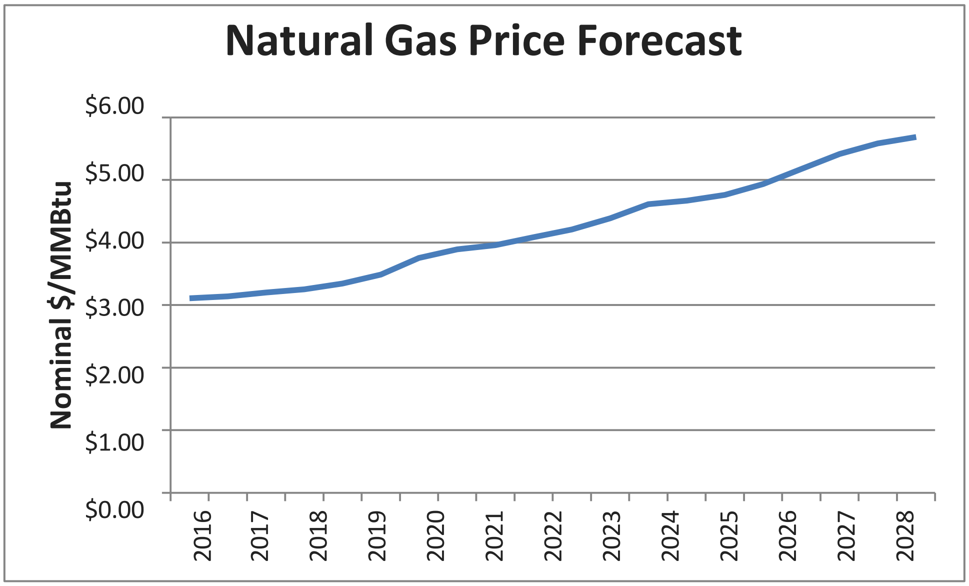


Figure 2: Natural Gas Price Forecast for Michigan Generation

3) Load Forecast

The load forecast for the MISO region in the MTEP17 Existing Fleet future was based on Module E submitted data growing at a 50% lower rate. However, Michigan specific demand and energy growth rates have been adjusted based on current data and models. The growth rates used in LRZ models of MISO's Mid-Term Clean Power Plan analysis are included below for comparison (Table 1). Additionally, Michigan has requested that MISO's model assume that the Empire Mine load in the Upper Peninsula be retired in 2016. The peak demand and energy for Michigan is listed by year in Table 2.

	MISO MTEP17 Existing Fleet Future Growth Rate	MI Phase II Growth Rates	LRZ 2 Mid-Term Analysis Growth Rate	LRZ 7 Mid-Term Analysis Growth Rate
Demand	0.37%	0.88%	0.6%	0.3%
Energy	0.37%	0.52%	0.6%	0.3%

Table 1: Demand and Energy Growth Rates

Type	2016	2017	2018	2019	2020	2021	2022	2023
Demand	21,689	21,857	22,021	22,175	22,309	22,444	22,582	22,722
Energy	105,715	105,406	105,221	105,128	105,069	105,074	105,142	105,273

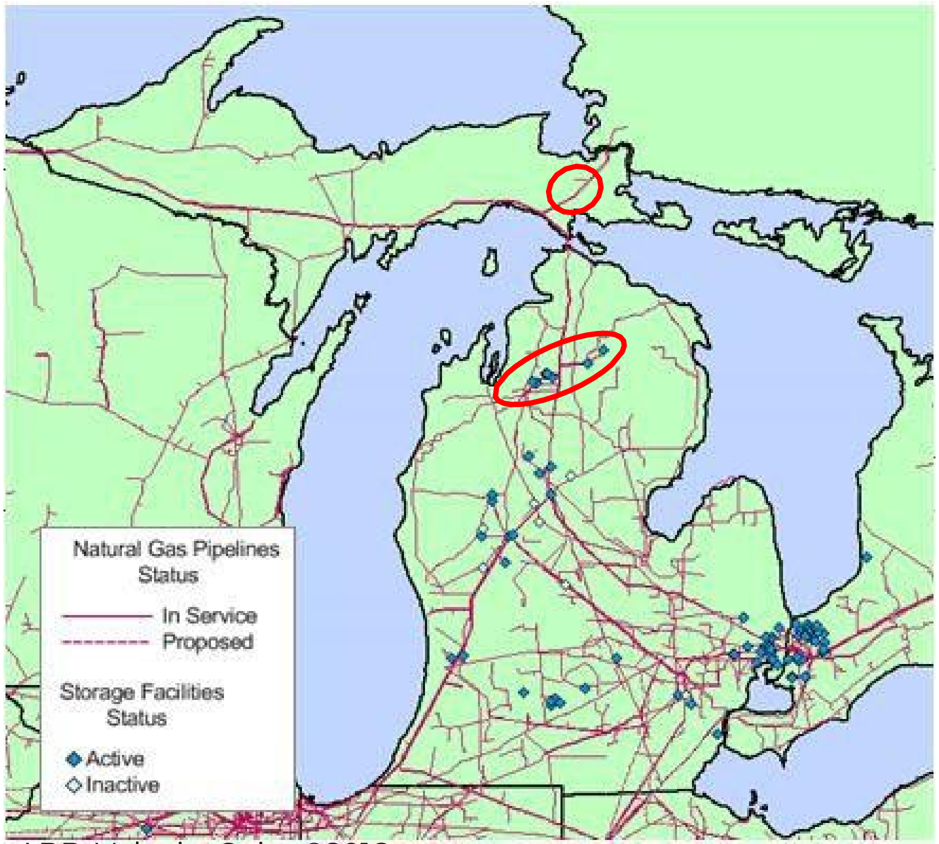
Type	2024	2025	2026	2027	2028	2029	2030	2031
Demand	22,865	23,008	23,219	23,471	23,726	23,985	24,247	24,513
Energy	105,466	105,717	106,352	107,240	108,191	109,202	110,276	111,411

Type	2032	2033	2034	2035
Demand	24,782	25,055	25,332	25,612
Energy	112,608	113,867	115,188	116,588

Table 2: Phase II Michigan Yearly Peak Demand and Energy

4) <u>Natural Gas Pipelines and Storage</u>

Michigan natural gas pipeline and storage facilities are mapped below (Figure 3). These were used to site potential natural gas generating units. One unit was sited near the natural gas storage and 345 kV systems in Otsego/Kalkaska counties, circled below. One unit was sited in the Eastern Upper Peninsula, also circled below.



MISO – Using ABB, Velocity Suite ©2016

Figure 3: Natural Gas Pipeline and Storage in Michigan

5) Generator Retirements

The following table shows Michigan's study generation retirements for analysis from Michigan's request (Table 3). Additional generation is retired based on the MTEP17 Existing Fleet future definitions. This includes retiring oil and gas units once they reach 55 years of age, and coal units when they reach 65 years.

Name	MW	Retired
Harbor Beach	121	2013
Trenton Channel	240	2016
B.C. Cobb	312	2016
Karn	312	2016
Whiting	345	2016
Endicott	55	2016
White Pine	20	2016
De Young	63	2017
Eckert	335	2018
Presque Isle	450	2020
River Rouge	651	2020-23
St. Clair	633	2022
Belle River	1177	2030

Table 3: Michigan Generator Retirements

6) Nuclear Generation:

The Michigan request included the following statuses for nuclear generation in or near Michigan.

Palisades: The existing Power Purchase Agreement expires in 2022, and the operating license expires in 2031. Entergy has announced retirement of the unit effective October 2022. The unit will be retired accordingly for this study.

Fermi: The nuclear unit at Fermi will be treated as though the operating license will be renewed. This unit will be in service for this study.

Quad Cities: The Quad Cities nuclear units were set to retire on June 1st, 2018. This retirement has since been retracted. These units will remain in service for this study.

Clinton: The Clinton nuclear unit has announced retirement beginning June 1st, 2017. The retirement has since been retracted. The unit will be retired in 2027 for this study.

7) Generation Additions:

The Michigan request specified certain generation additions to be included in the study. These units were considered as base case assumptions in this analysis (Table 4). Additional generation was added to account for retired generation and growing load, based on the future variables for the Existing Fleet future (Table 5).

Name	Type	MW	In-Service
Alpine	Combustion Turbine	410	2016
Cross Winds II	Wind	44	2018
Pine River Wind	Wind	161	2019
J703	Internal Combustion	128	2020
J704	Internal Combustion	55	2020
J572	Combined Cycle	165	2018

Table 4: Michigan Generator Additions

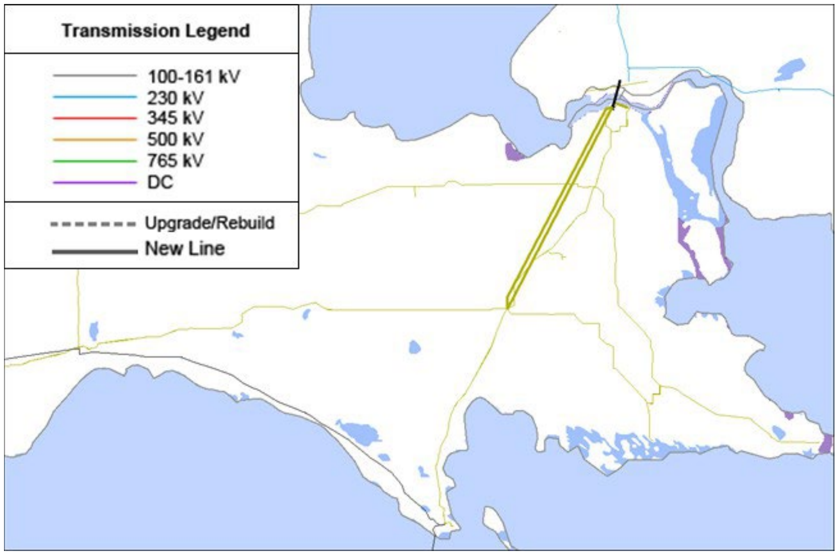
Name	Category	MW	Commission	POI
RRF MISO CT: 006	CT Gas	50.0	1/1/2023	Keystone 138 kV
RRF MISO CT: 009	CT Gas	100.0	1/1/2024	Thetford 138 kV
RRF MISO CT: 013	CT Gas	100.0	1/1/2024	Gaylord 138 kV
RRF MISO CT: 019	CT Gas	200.0	1/1/2025	Monroe 345 kV
RRF MISO CT: 022	CT Gas	200.0	1/1/2025	Zeeland 345 kV
RRF MISO CT: 030	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 031	CT Gas	100.0	1/1/2024	Toll Road 120 kV
RRF MISO CT: 032	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 035	CT Gas	100.0	1/1/2024	Super 120 kV
RRF MISO CT: 037	CT Gas	200.0	1/1/2025	Hancock 120 kV
RRF MISO CT: 051	CT Gas	300.0	1/1/2030	B. Foot 345 kV
RRF MISO CT: 059	CT Gas	100.0	1/1/2026	N. East 120 kV
RRF MISO CT: 062	CT Gas	100.0	1/1/2026	Thetford 138 kV
RRF MISO CT: 091	CT Gas	200.0	1/1/2029	Cobb 138 kV
RRF MISO PV: DG CONS	Solar PV	29.0	1/1/2021	Top 10 loads
RRF MISO PV: DG DECO	Solar PV	35.4	1/1/2021	Top 10 loads
RRF MISO PV: DG WPSC	Solar PV	1.8	1/1/2021	Top 10 loads
RRF MISO PV: Tier 1 - 16	Solar PV	50.0	1/1/2021	Nelson Road 345 kV
RRF MISO Wind: RGOS MI-B	Wind	45.0	1/1/2026	Bauer 345 kV
RRF MISO Wind: RGOS MI-C	Wind	45.0	1/1/2026	Rapson 345 kV
RRF MISO Wind: RGOS MI-D	Wind	45.0	1/1/2026	Rapson 345 kV
RRF MISO Wind: RGOS MI-E	Wind	45.0	1/1/2026	Bauer 345 kV
RRF MISO Wind: RGOS MI-F	Wind	45.0	1/1/2026	Greenwood 345 kV
RRF MISO Wind: RGOS MI-I	Wind	45.0	1/1/2026	Palisades 345 kV
RRF MISO Wind: RGOS MI-B	Wind	48.0	1/1/2031	Bauer 345 kV
RRF MISO Wind: RGOS MI-C	Wind	48.0	1/1/2031	Rapson 345 kV
RRF MISO Wind: RGOS MI-D	Wind	48.0	1/1/2031	Rapson 345 kV
RRF MISO Wind: RGOS MI-E	Wind	48.0	1/1/2031	Bauer 345 kV
RRF MISO Wind: RGOS MI-F	Wind	48.0	1/1/2031	Greenwood 345 kV
RRF MISO Wind: RGOS MI-I	Wind	48.0	1/1/2031	Palisades 345 kV

Table 5: Michigan Generator Expansions for the Existing Fleet Future

III. Transmission Ideas

Sixteen transmission ideas were submitted for study in Phase II. These options ranged from using/upgrading existing infrastructure to major transmission additions. Every solution to the options studied involved a new transmission line connection to Ontario. Some of the solutions included an option to isolate a generator in Sault Ste. Marie, Ontario from the IESO transmission system and connect it to the Michigan system via new transmission. The following section describes the transmission ideas that were studied.

1. <u>Transmission Idea MI-1</u>



i) Michigan Facilities:

(1) New 115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line
(2) New 115/69 kV transformer at NEWSUB
(3) New 69 kV line from Magazine St. to Portage
(4) Two new 69 kV lines from NEWSUB to Pine River
(5) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connection and tie the line to one of the new 69 kV lines from NEWSUB. Use the newly opened terminal at Pine River for the 2nd 69 kV line from NEWSUB.

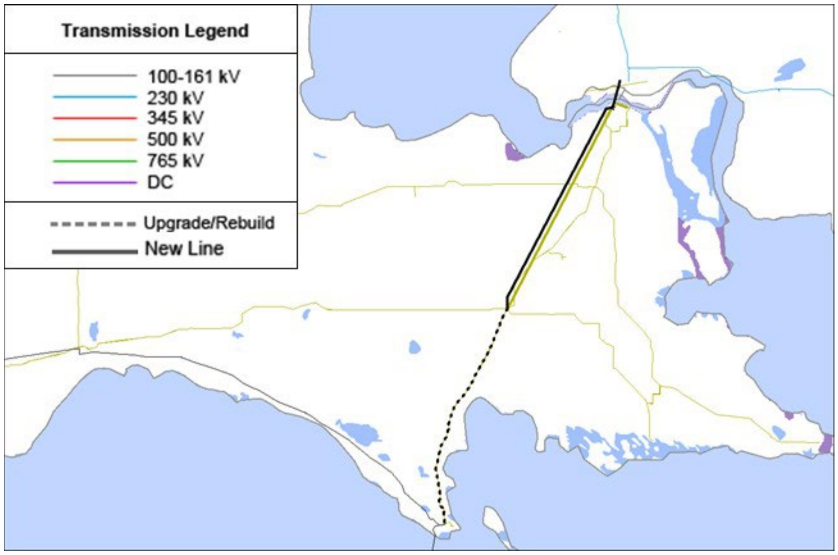
ii) Interconnection:

(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie to NEWSUB. Adjust system to disconnect the existing plant from Ontario's system.
(4) Change the voltage of NEWSUB and associated transformer from 115/69 kV to 138/69 kV.

2) <u>Transmission Idea MI-2</u>



i) Michigan Facilities:

(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) New 138 kV line from NEWSUB to Pine River
(6) New 69 kV line from NEWSUB to Pine River
(7) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connection. Tie the line to the new 138 kV line from NEWSUB and operate at 138 kV. Use the newly opened terminal at Pine River for the new 69 kV line from NEWSUB.

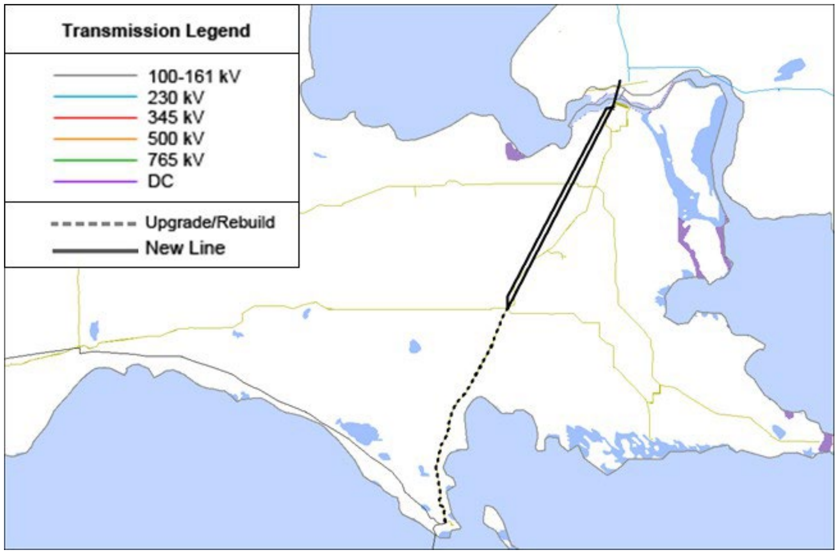
ii) Interconnection:

(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie to NEWSUB. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

3) <u>Transmission Idea MI-3</u>



i) Michigan Facilities:

(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line.
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) Two new 138 kV lines from NEWSUB to Pine River
(6) New 138 kV switching station at Pine River
(7) New 138/69 kV transformer at Pine River
(8) New 69 kV line from NEWSUB to Pine River
(9) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connections. Tie the lines to the new 138 kV switching station. Use a newly opened terminal at Pine River for the new 138/69 kV transformer.

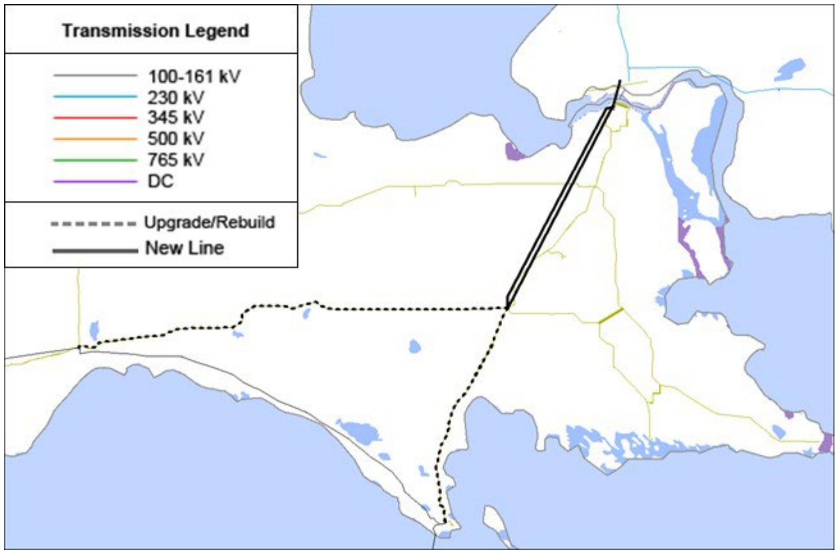
ii) Interconnection:

(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

4) <u>Transmission Idea MI-4</u>



i) Michigan Facilities:

(1) New 138/115/69 kV substation (NEWSUB) tapping the existing Magazine St. – 3 Mile 69 kV line.
(2) New 138/115 kV transformer at NEWSUB
(3) New 138/69 kV transformer at NEWSUB
(4) New 69 kV line from Magazine St. to Portage
(5) New 69 kV from Pickford to a tap on Pine River – Rockview
(6) Rebuild Pine River – Hiawatha 69 kV line to 138 kV
(7) Two new 138 kV lines from NEWSUB to Pine River
(8) New 138 kV switching station at Pine River
(9) New 138/69 kV transformer at Pine River
(10) New 69 kV line from NEWSUB to Pine River
(11) Reconfigure Pine River 69 kV substation. Remove the Straits – Pine River 69 kV connections. Tie the lines to the new 138 kV switching station. Use a newly opened terminal at Pine River for the new 138/69 kV transformer.

ii) Interconnection:
(1) New 115/115 kV Phase Angle Regulating transformer at NEWSUB
(2) New 115 kV tie line from NEWSUB to Clergue TS (IESO)

Or

(3) Two new 138 kV lines connecting an existing combined cycle gas power plant in Sault Ste. Marie. Adjust system to disconnect the existing plant from Ontario's system.
(4) The 138/115 kV transformer will no longer be needed

5) Transmission Idea MI-5

The base transmission for MI-5 is the same as MI-1. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformer of NEWSUB to 230/69 kV.

6) Transmission Idea MI-6

The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

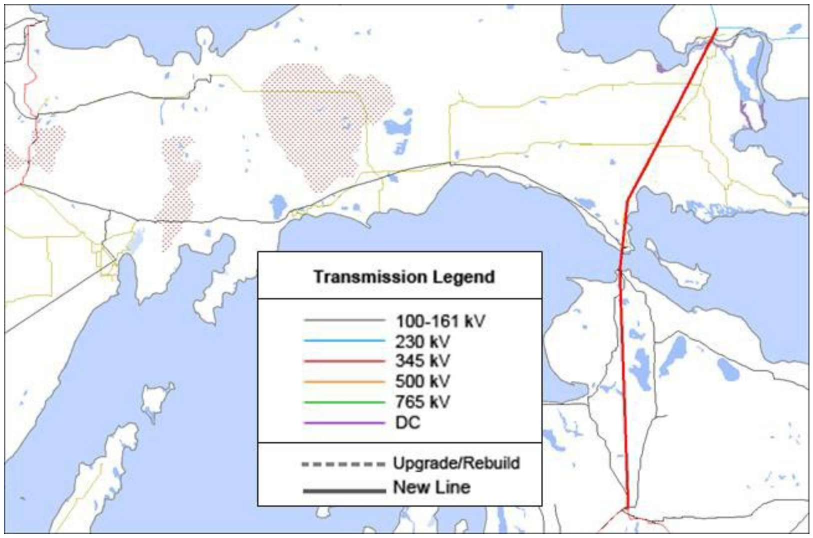
7) Transmission Idea MI-7

The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

8) Transmission Idea MI-8

The base transmission for MI-6 is the same as MI-2. The difference is the voltage level of the tie line. For MI-5, the interconnection is an increase to a new 230 kV line from NEWSUB to Third Line (IESO). This also entails changing the voltage level and associated transformers of NEWSUB to 230/138/69 kV.

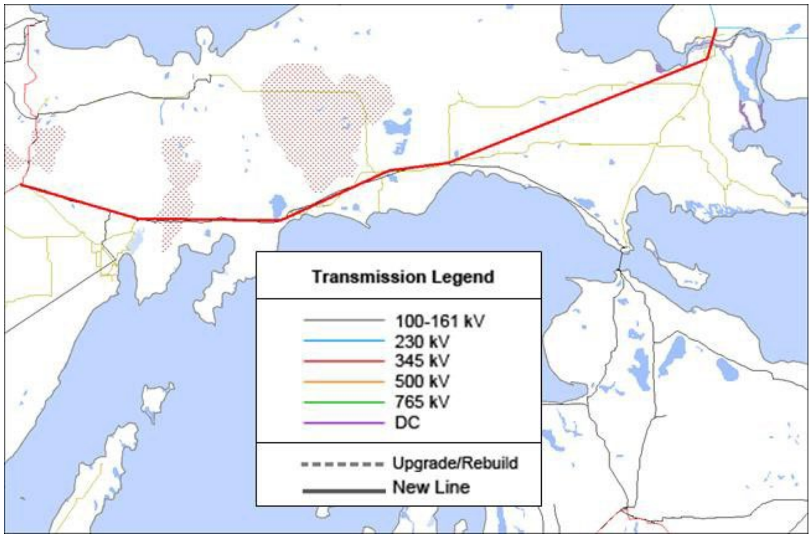
9) <u>Transmission Idea MI-9</u>



i) Facilities:

(1) New 345 kV line from Livingston to Third Line (IESO)
(2) New 345 kV substation at Third Line (IESO)
(3) New 345/230 kV transformer at Third Line (IESO)

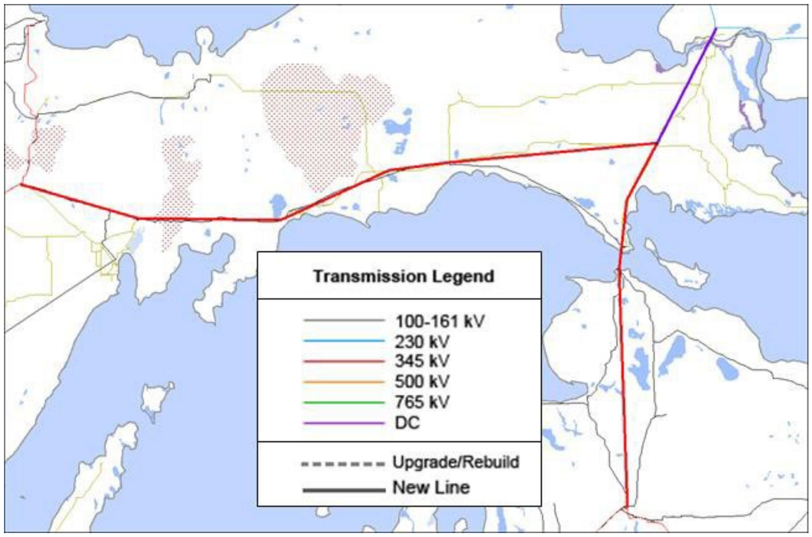
10) <u>Transmission Idea MI-10</u>



i) Facilities:

(1) New 345 kV line from Arnold to Third Line (IESO)
(2) New 345 kV substation at Third Line (IESO)
(3) New 345/230 kV transformer at Third Line (IESO)

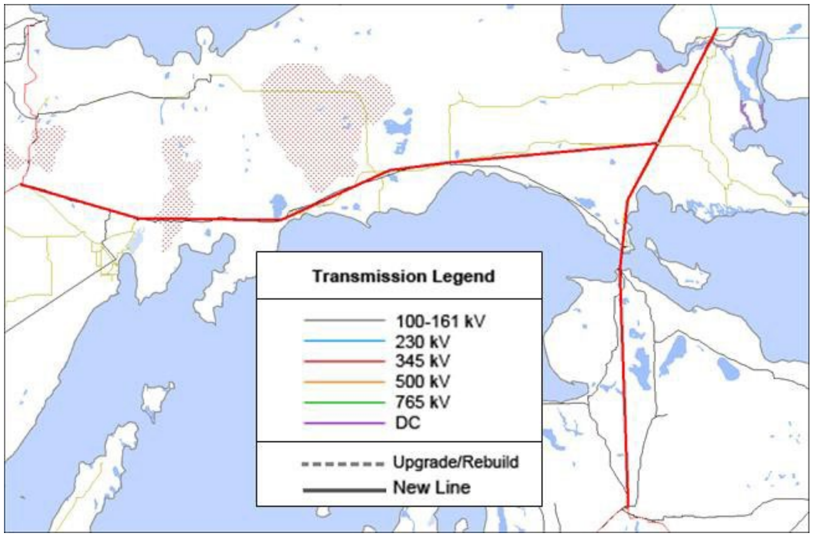
11) Transmission Idea MI-11



i) Facilities:

(1) New 345 kV line from Arnold to Pine River
(2) New 345 kV line from Livingston to Pine River
(3) New 345 kV substation at Pine River
(4) New 345 kV line from Pine River to Third Line (IESO)
(5) New HVDC/345/230 kV substation at Third Line (IESO) (back to back AC/DC/AC)

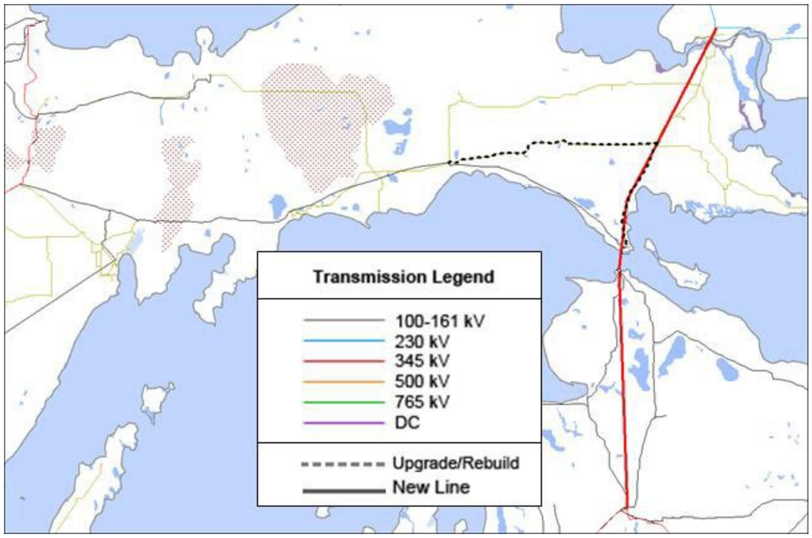
12) Transmission Idea MI-12



i) Facilities:

(1) New 345 kV line from Arnold to Pine River
(2) New 345 kV line from Livingston to Pine River
(3) New 345 kV substation at Pine River
(4) New 345 kV line from Pine River to Third Line (IESO)
(5) New 345kV substation at Third Line (IESO)
(6) New 345/230 kV transformer at Third Line (IESO)

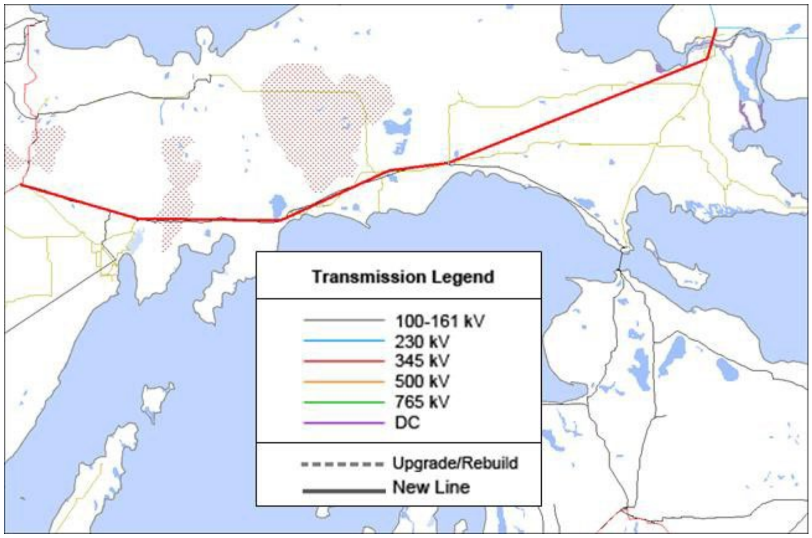
13) Transmission Idea MI-13



i) Facilities:

(1) New 345 kV line from Livingston to McGulpin
(2) New 345 kV substation at McGulpin
(3) New 345/138 kV transformer at McGulpin
(4) New 345 kV line from McGulpin to Pine River
(5) New 345/138 kV substation at Pine River
(6) New 345/138 kV transformer at Pine River
(7) New 138/69 kV transformer at Pine River
(8) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines
(2) to the 138 kV station and operate at 138 kV
(9) New 345 kV line from Pine River to Third Line (IESO)
(10) New 345 kV substation at Third Line (IESO)
(11) New 345/230 kV transformer at Third Line (IESO)
(12) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

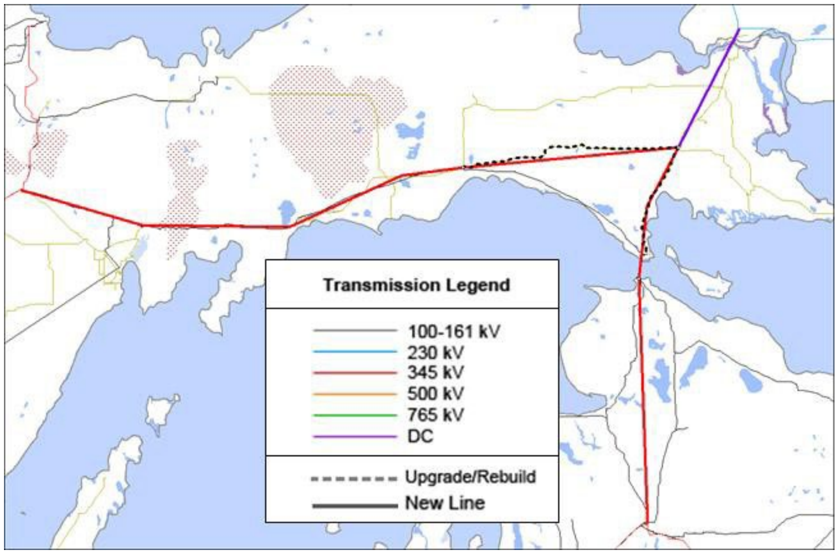
14) <u>Transmission Idea MI-14</u>



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Third Line
(5) New 345 kV substation at Third Line (IESO)
(6) New 345/230 kV transformer at Third Line (IESO)
(7) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

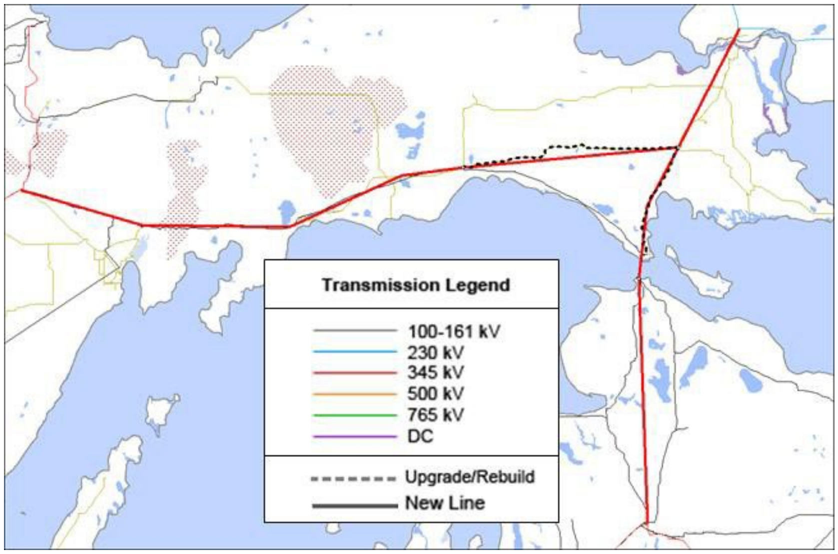
15) Transmission Idea MI-15



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Pine River
(5) New 345 kV line from Livingston to McGulpin
(6) New 345 kV substation at McGulpin
(7) New 345/138 kV transformer at McGulpin
(8) New 345 kV line from McGulpin to Pine River
(9) New 345/138 kV substation at Pine River
(10) New 345/138 kV transformer at Pine River
(11) New 138/69 kV transformer at Pine River
(12) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines (2) to the 138 kV station and operate at 138 kV
(13) New 345 kV line from Pine River to Third Line (IESO)
(14) New HVDC/345/230 kV substation at Third Line (IESO) (back to back AC/DC/AC)
(15) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

16) <u>Transmission Idea MI-16</u>



i) Facilities:

(1) New 345 kV line from Arnold to Hiawatha
(2) New 345 kV substation at Hiawatha
(3) New 345/138 kV transformer at Hiawatha
(4) New 345 kV line from Hiawatha to Pine River
(5) New 345 kV line from Livingston to McGulpin
(6) New 345 kV substation at McGulpin
(7) New 345/138 kV transformer at McGulpin
(8) New 345 kV line from McGulpin to Pine River
(9) New 345/138 kV substation at Pine River
(10) New 345/138 kV transformer at Pine River
(11) New 138/69 kV transformer at Pine River
(12) Reconfigure Pine River 69 kV substation. Move Pine River – Straits 69 kV lines (2) to the 138 kV station and operate at 138 kV
(13) New 345 kV line from Pine River to Third Line (IESO)
(14) New 345kV substation at Third Line (IESO)
(15) New 345/230 kV transformer at Third Line (IESO)
(16) Rebuild 69 kV line from Hiawatha to Pine River to 138 kV

IV. Cost Estimates

Transmission cost estimates were provided by MISO's Competitive Transmission Administration team. These costs are high level estimates that are not comparable to MISO planning or scoping level cost estimates. Generator cost estimates were sourced from MTEP17 capital costs assumptions for combined cycle (CC) and combustion turbine (CT) power plants. Reciprocating internal combustion engine (RICE) power plant cost estimates were sourced from the UMERC Certificate of Need Case No. U-18224. Detailed cost breakdowns for each option can be found in Appendix C.

Transmission Idea	IESO Tie Cost ($M)	Radial Gen Cost ($M)
MI-1	85.4	89.8
MI-2	92.9	89.8
MI-3	112.1	109.1
MI-4	183.4	180.4
MI-5	93.8	
MI-6	102.3	
MI-7	121.6	
MI-8	192.9	
MI-9	347.1	
MI-10	490.0	
MI-11	1,138.9	
MI-12	787.0	
MI-13	460.0	
MI-14	572.4	
MI-15	1,259.2	
MI-16	907.4	
Kalkaska CC	430.0	
Chippewa County CC	108.0	
Chippewa County RICE	132.4	
Chippewa County CT	92.0	

Table 6: High Level Cost Estimates

V. Reliability Analysis and Results

MISO conducted a reliability analysis of the transmission and generation ideas. This analysis entailed running P1 and P2 (single element) outages in Michigan. MTEP17 Shoulder Peak and Summer Peak models were used for analysis. Additionally, IESO performed an analysis of the Ontario system, specifically around Sault Ste. Marie area, to identify transfer capabilities of the Ontario system. IESO's analysis determined three levels of transfer, depending on the amount of system enhancements that were to be made to transmission system[4]. Accordingly, MISO studied the three transfer levels on the MISO system.

Scenario	Export Capability		Description
	Summer	Winter	
Without system enhancements	50 MW	25 MW	Limited by thermal ratings on the local, 115 kV transmission system
With system enhancements	125 MW	75 MW	Required enhancements: - Mitigation of thermal constraints on the 115 kV system - Reconfiguration of 230 kV circuits supplying the SSM system[2] Limited by Third Line TS autotransformers and the thermal rating of 115 kV circuits connecting Steelton/Patrick St. TS and Clergue TS
With system enhancements	325 MW	275 MW	Required enhancements: - New 230 kV circuit from Clergue TS to Third Line TS (approximately 5 km) - Reconfiguration of 230 kV circuits supplying the SSM system - Additional voltage control facilities Limited by thermal ratings of 230 kV circuits supplying SSM system

Table 7: IESO Reliability Analysis[5]

When adding the transmission ideas that included a transmission tie between the Ontario and Michigan transmission systems, the base case showed overloads and high flows on the tie lines flowing into Michigan. Phase angle differences between the Ontario and MISO systems resulted in high, uncontrollable flows along the tie lines. To address these concerns, MISO incorporated Phase Angle Regulating transformers into the transmission ideas tying to the Ontario system. This is reflected in the transmission idea descriptions and costs in previous sections.

When studying the various transfer levels, significant and widespread reliability issues were identified at the 325 MW transfer level. Accordingly, MISO determined this was an unreasonable transfer level due to the high cost associated with mitigating the numerous issues. As such, the lower voltage options (MI-1 to MI-8) were deemed more appropriate due to the low transfer limitations (125 MW maximum).

[4] See Appendix D, Sault St. Marie Export Study For MISO

[5] Export Capability is based on current system conditions and is provided for the purpose of the Michigan Exploratory Transmission Study. It is subject to change based on future system conditions. The acronym "SSM" stands for "Sault Ste. Marie".

No reliability issues were seen in any of the transmission ideas when analyzing the 50 MW transfer level. The 125 MW transfer level showed reliability issues for MI-1, MI-2, MI-5, and MI- 6 due to limited power transfer capabilities of the local system near the new Michigan/Ontario tie. The transmission options do not provide enough outlet capacity for the new transfer. Because the transmission ideas are incremental in terms of transmission build out, issues seen in the lower-numbered options are addressed by the transmission upgrades in higher- numbered options. Option MI-3 and MI-7 had a few 69 kV thermal issues for one contingency only. Option MI-4 showed no reliability concerns at the 125 MW transfer level. Adding a 100 MW power plant in Chippewa County, MI also showed no reliability issues when studied.

VI. Economic Analysis and Results

MISO performed a production cost analysis using the models developed specifically for Phase II. PROMOD was used to perform simulations for each hour of three study years: 2021, 2026, and 2031. MISO studied all transmission and generation ideas in the study.

The higher voltage solutions (MI-9 to MI-16) were studied in parallel with the reliability assessment. As such, these scenarios were studied at a 400 MW transfer level. The reliability analysis determined a 125 MW transfer to be a reasonable transfer limit. The results of the 400 MW transfer for options MI-9 to MI-16 are still included for reference. Reliability upgrades and associated costs are not included in these results.

While initially studied at a 200 MW transfer level due to the parallel economic and reliability analysis, the lower voltage options (MI-1 to MI-8) were re-studied at the 125 MW transfer level, as per the reliability analysis. Due to the reliability concerns with MI-1, MI-2, MI-5, and MI-6, economic results are not shown for these options. The remaining transmission options incorporate the reliability upgrades that would be necessitated. The economic results for MI-3, MI-4, MI-7, and MI-8 are reported at the 125 MW transfer level. MISO used a combined cycle power plant located in Sault Ste. Marie, Ontario to simulate up to 125 MW of power transfer from Ontario to Michigan. This unit was used for both the radial generator connection and tie line options. A phase angle regulator was part of the tie line options, as previously described.

The following economic results list the 20 year present value costs, 20 year present value adjusted production cost (APC) benefits, 20 year present value net impact, and 20 year present value benefit to cost ratios. The 20 year present value costs are created using the costs previously listed, and applying a MISO gross-plant weighted average discount rate and inflation rate for 20 years. Similarly, the APC benefits are extrapolated using the APC savings from the 2021, 2026, and 2031 study years over a 20 year timeframe. The net impact is calculated by subtracting the project costs from the project benefits. Negative numbers (red) indicate costs higher than provided benefits. A benefit to cost ratio (B/C) is a similar comparison. It is calculated by dividing the total benefits by the total cost. A 1.0 B/C indicates the project costs are equal to the benefits. Ratios below 1.0 indicate costs outweighing the benefits provided. Ratios above 1.0 indicate benefits outweighing costs.

Project IDs	Assumed Max Import (MW)	20 Year PV Cost (M$)	20 Year PV MI APC Benefit (M$)	20 Year PV Net Impact	20 Year PV B/C Ratio
MI-3	125	(145.42)	19.00	(124.81)	0.13
MI-4	125	(240.51)	28.00	(210.89)	0.12
MI-7	125	(162.09)	23.00	(128.73)	0.14
MI-8	125	(257.17)	29.00	(217.81)	0.11
MI-9	400	(462.91)	198.00	(264.91)	0.43
MI-10	400	(653.49)	218.00	(435.49)	0.33
MI-11	400	(1518.71)	242.00	(1276.71)	0.16
MI-12	400	(1049.53)	219.00	(830.53)	0.21
MI-13	400	(613.48)	202.00	(411.48)	0.33
MI-14	400	(763.35)	218.00	(545.35)	0.29
MI-15	400	(1679.24)	244.00	(1435.24)	0.15
MI-16	400	(1210.06)	230.00	(980.06)	0.19

Table 8: Transmission Options Economic Analysis

Project IDs	Generator Capacity (MW)	20 Year PV Cost (M$)	20 Year PV MI APC Benefit (M$)	20 Year PV Net Impact	20 Year PV B/C Ratio
Kalkaska CC	400	(573.43)	287.00	(286.43)	0.50
Chippewa County CC	100	(144.02)	27.00	(117.02)	0.19
Chippewa County RICE	100	(176.59)	30.00	(146.59)	0.17
Chippewa County CT	100	(122.69)	12.51	(110.18)	0.10

Table 9: Generation Options Economic Analysis

In addition to the generation only and transmission only options, generation was also combined with the transmission ideas to explore the combined impact to the production costs. Additionally, the voltage source converter (VSC) Mackinac Straits flow control device was simulated at current operating limitations as well as maximum equipment capabilities.

1) <u>Combined Generation and Transmission</u>
The PROMOD analysis showed economic benefits that were additive. When comparing the "generator only" benefits and the "transmission only" benefits to the benefits of combined generation and transmission scenarios, the benefits of the combined scenarios were comparable to the sum of the "generator only" benefits and the "transmission only" benefits. Accordingly, economic results are reported separately (generation only and transmission only).

2) VSC Sensitivity

The VSC was tested at maximum capability (+/- 226 MVA) as well as current operating limitations for generation only, transmission only, and combined generation and transmission scenarios. The economic benefits of allowing the VSC to operate at the maximum equipment capabilities were within 0%-5% higher than operating the VSC at the current operational limitations. To increase the VSC capabilities, reliability upgrades would be required in addition to transmission ideas to reliably handle the higher flows.

3) Radial Generator vs. Ontario System Tie Line

The two scenarios resulted in comparable economic benefits/production costs. The difference between the two options is the costs associated with each option and are listed in Table 6.

VII. Conclusions

The economic and reliability analyses determined that all of the transmission and generation solutions did not provide enough economic benefit to cover the costs of such projects. Due to low transfer limitations (125 MW) identified by the reliability analysis, as well as relatively high costs associated with the projects, the amount of economic potential was limited. Generation and transmission options in the Upper Peninsula provided comparable amounts of economic benefits for similar costs.

Appendix A

RICK SNYDER
GOVERNOR

STATE OF MICHIGAN
EXECUTIVE OFFICE
LANSING

BRIAN CALLEY
LT. GOVERNOR

August 17, 2016

John Lawhorn
Senior Director of Policy and Economic Studies
Midcontinent Independent System Operator
P.O. Box 4202
Carmel, IN 46082-4202

Dear Mr. Lawhorn,

The Michigan Agency for Energy (MAE) requests that the Midcontinent Independent System Operator (MISO) conduct system analyses to help the State of Michigan better understand the potential production cost savings, reliability, and resource adequacy benefits of transmission including increased import capability, and generation expansion in Michigan. MISO's regional planning and modeling expertise will be invaluable to us as we set Michigan on a path toward adaptable, reliable, affordable and environmentally protective energy. Specifically, we would ask that MISO conduct a near and long term evaluation of transmission expansion better connecting the Upper Peninsula of Michigan to our Canadian neighbors as well as to lower Michigan.

Many fundamental characteristics of the Bulk Electric System (BES) have evolved over the last five years on both sides of the international border, and change to the system is expected to accelerate within Michigan. With so many changes to the overall MISO system, but especially the challenges that Michigan residents and business face, it is critical for Michigan that MISO conduct analyses that consider updated system assumptions and scenarios specific to Michigan's unique peninsulas. For MISO's consideration, an attachment to this letter outlines recent and expected changes to the electricity system that could have an impact in Michigan.

Specifically, MAE requests that MISO conduct a near and long term regional evaluation of potential production cost savings, reliability, and resource adequacy benefits of transmission and generation expansion in MISO's northern footprint, specifically Michigan's eastern Upper Peninsula (part of Zone 2) up to Sault Ste. Marie, Ontario and northern Lower Peninsula (Zone 7) at the Straits of Mackinac down to the northernmost portion of the existing 345 kV transmission line near Gaylord, MI. Alternatively, MAE requests MISO update its 2012 Northern Area Study for these same Michigan areas, but in that event, to work more closely with the Ontario grid operators to ensure possible benefits are fully studied, as we understand the interconnection is to an area that has high production potential compared to the load but constrained transmission. Ontario's next Long-Term Energy Plan process will commence this summer, so this may be an excellent opportunity to work together.

Further, MAE is interested to know the impacts that a new natural gas-fired electric generating station located strategically in northern lower Michigan could have on the BES, especially in conjunction with the transmission upgrades. As you know, Michigan is likely to have to add capacity, likely in the form of a natural gas plant, in the near term. An evaluation as to the ability of strategic location of that plant to be part of an overall cost-lowering strategy is something that would be especially beneficial at this time.

Specifically, MAE would like MISO to model the production cost savings, reliability, resource adequacy, and power flows that would result from a natural gas-fired generating station located in the northcentral Lower Peninsula of Michigan. The optimal site to model new gas-fired generation is near existing underground natural gas storage fields in Otsego and Kalkaska counties, intrastate natural gas pipelines, and 345 kV electric transmission lines in the northern Lower Peninsula.

MAE appreciates your consideration of this request and are happy to address any additional questions you would have. MAE staff would be happy to provide any technical assistance, government-to-government outreach, or any other support that would be requested by MISO to assist it in conducting this study.

Sincerely,

Valerie Brader

Rick Snyder
Governor

Valerie Brader
Executive Director

Michigan Agency for Energy

Attachment

Appendix B

August 9, 2016

Mr. John Lawhorn
Senior Director of Policy and Economic Studies
Midcontinent Independent System Operator
P.O. Box 4202
Carmel, IN 46082-4202

Dear Mr. Lawhorn,

The Michigan Agency for Energy (MAE) and the Michigan Public Service Commission (MPSC) request that the Midcontinent Independent System Operator (MISO) conduct a study to help the State of Michigan better understand the effects of declining reserve margins in emergency situations. As you know, Michigan has recently experienced a large number of plant retirements in the very recent past, and MISO's regional planning and modeling expertise is necessary and invaluable to us as we look to determine whether Michigan is on track to continue meeting its reliability goals, including the goal never to experience a massive outage due to a lack of supply.

Many fundamental characteristics of the Bulk Electric System (BES) have evolved over the last five years, and change to the system is expected to accelerate. With system-wide capacity shortfalls in MISO anticipated as soon as 2018 per the 2016 MISO-OMS Survey, it is critical for Michigan to understand whether our system still can support the level of reliability it was able to show a few years ago. To that end, we request that MISO conduct a scenario analysis that considers updated system assumptions specific to Michigan's unique structure. An attachment to this letter outlines recent and expected changes to the electricity system that could have an impact in Michigan.

Declining reserve margins in MISO and in Michigan require that we more fully understand the implications on Michigan, specific from MISO, of certain energy emergencies. As such, MAE requests that MISO assess and inform Michigan of vulnerabilities associated with simultaneous planned or unplanned outages at Palisades Power Plant (Palisades) and Fermi, Unit 2 (Fermi 2) nuclear energy facilities. These two facilities are capable of producing a combined 1,855 MW of reliable baseload power.

We did not pick this scenario randomly. Rather, it is our goal to understand what would happen in the summer of 2018 if we had a recurrence of the events that occurred in the summer of 2012, when there were simultaneous outages at these two nuclear facilities while MISO was under a hot weather alert. Obviously, in 2012, we were able to sustain the grid in those conditions. We would like to know if that would still be expected to be true.

Accounting for the retirement of numerous coal-fired generation this summer and other expected future changes to the system, we request that MISO conduct an analysis that assumes Palisades and Fermi 2 are offline, and then determines for MISO zone 7 (1) what internal generating capacity, (2) what contracted capacity, (3) what import capability; and (4) what capacity and transmission service from outside of Michigan, could be available to serve Michigan load. We appreciate your consideration of this request and are happy to address any additional questions you would have and provide any technical assistance that would be requested in support of this study.

Sincerely,

<table>
<tr><td>Valerie Brader
Executive Director
Michigan Agency for Energy</td><td>Sally Talberg
Chairman
Michigan Public Service Commission</td></tr>
</table>

System Conditions for MISO's Consideration

Generation

1. Retirement of coal-fired generators in Michigan:
   a. In 2013, one DTE Harbor Beach unit (121 MW) retired.
   b. In 2016:
      i. Two DTE Trenton Channel units (7a and 8) (240 MW) retired.
      ii. Two CE BC Cobb units in Muskegon (312 MW) retired.
      iii. Two CE JC Karn-Weadock units in Essexville (312 MW) retired.
      iv. Three CE JR Whiting units in Erie (345 MW) retired.
      v. One Michigan South Central Power Agency's Endicott unit in Litchfield (55 MW) retired.
   c. In 2017, three Holland Board of Public Works DeYoung units (3, 4, and 5) (63 MW) retiring.
   d. In 2018, six Lansing Board of Water and Light Eckert units (335 MW) retiring.
2. Palisades Nuclear power station offline after 2022 (PPA Expiration) (NRC operating license expires in 2031).
3. Fermi 2 nuclear power station remains online after 2025 (NRC license renewal is expected)
4. Announced retirement of Quad Cities nuclear power station on June 1, 2018.
5. Announced retirement of Clinton nuclear power station on June 1, 2017.
6. New Wolverine 410 MW Alpine natural gas simple cycle generating unit in Elmira Township, MI.
7. New 280 MW (summer peak) natural gas combined cycle generation in Marquette County, MI with expected in-service date in December 2019 (Project J394).
8. Impact of generation pseudo-ties out of MISO.

Load

9. Retirement of Empire Mine in 2016.

Transmission

10. Plains to National proposed transmission line moved to MTEP Appendix B.
11. 230 kV underground line from Sault Ste. Marie, Ontario to Sault Ste. Marie, MI. Presidential Permit granted.
12. Congestion mitigation of Lake Michigan loop flow.
13. Increased transfer capability across the Straits of Mackinac.
14. Maintenance flexibility for northern Lower Peninsula transmission.

15. Management flexibility of Ludington Pumped Storage asset.
16. Contribution of high voltage, direct-current flow control device and associated substation in eastern Upper Peninsula.
17. Approved MTEP reliability projects in advanced stages of development.

Other Considerations

18. New Michigan Upper Peninsula (MI-UP) Load Balancing Authority area.
19. Updated MTEP Models and Futures Scenarios.
20. Impacts voltage and local reliability (VLR) constraints and Revenue Sufficiency Guarantee (RSG) make-whole payments.

Appendix C: Detailed Cost Breakdowns

Transmission Idea MI-1								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	115/69	NEWSUB			New substation for connection to Ontario's system	11.8	
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to 1 of 2 of the new Sub A - Pine River 69 kV lines. Use the newly opened terminal at Pine River to connect the 2nd Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	115/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	69	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Substation	138/69	NEWSUB			New substation for connection to Ontario's system		11.8
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system		7.5
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-2								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to the new Sub A - Pine River 138 kV line and operate at 138 kV. Use the newly opened terminal at Pine River to connect the Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-3								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-4								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	138/115/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/115	NEWSUB			New transformer	7.5	
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	115	NEWSUB	Clergue	7	New tie line to Ontario	8.7	
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	Pickford	Tap	10	New 69 kV line from a tap on the Pine River - Rockview 69 kV to Pickford 69 kV	11.8	11.8
New	PAR	115/115	NEWSUB			New phase angle regulating transformer	4.3	
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7
New	Line	138	NEWSUB	Local Gen	7	New tie line to Ontario		8.7

Transmission Idea MI-5								
Adjustment Type	**Facility Type**	**Voltage (kV)**	**From Substation**	**To Substation**	**Estimated Length (Miles)**	**Description**	**IESO Tie Cost (M$)**	**Radial Generator Cost (M$)**
New	Substation	230/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to 1 of 2 of the new Sub A - Pine River 69 kV lines. Use the newly opened terminal at Pine River to connect the 2nd Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	115/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	Line	69	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-6								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
Reconfigure	Substation	69	Pine River			Remove connection of 1 of 2 of the Pine River - Straights 69 kV lines. Tie the line to the new Sub A - Pine River 138 kV line and operate at 138 kV. Use the newly opened terminal at Pine River to connect the Sub A - Pine River 69 kV line.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-7								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-8								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	230/138/69	NEWSUB			New substation for connection to Ontario's system	11.8	11.8
New	Substation	138	Pine River			New substation or switching station at Pine River	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	230/138	NEWSUB			New transformer	8.5	8.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Transformer	138/69	NEWSUB			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	230	NEWSUB	Third Line	10	New tie line to Ontario	13.6	13.6
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5
New	Line	138	NEWSUB	Pine River	25	New Line 2 of 2 from new sub to Pine River	23.6	23.6
New	Line	138	NEWSUB	Pine River	25	New Line 1 of 2 from new sub to Pine River	23.6	23.6
Reroute	Line	69	Magazine St.	3 Mile	1.0 + 3.0	Reroute existing line Magazine St. - 3 Mile through the new substation	4.7	4.7
New	Line	69	Magazine St.	Portage	1	New line from Magazine St. to Portage	1.2	1.2
New	Line	69	Pickford	Tap	10	New 69 kV line from a tap on the Pine River - Rockview 69 kV to Pickford 69 kV	11.8	11.8
New	PAR	230/230	NEWSUB			New phase angle regulating transformer	7.8	

Transmission Idea MI-9

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Livingston	Third Line	115.5	New 345 kV tie from Livingston to Ontario	326.9	326.9

Transmission Idea MI-10

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Arnold	Third Line	166	New 345 kV tie from Arnold to Ontario	469.8	469.8

Transmission Idea MI-11

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	HVDC/345/230	Third Line			New substation in Ontario with 230 kV AC/DC/ 345 kV AC conversion	372.1	372.1
New	Substation	345	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Line	345	Arnold	Pine River	150	New 345 kV Line	424.5	424.5
New	Line	345	Livingston	Pine River	82.5	New 345 kV Line	233.5	233.5
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4

Transmission Idea MI-12								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Substation	345	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Line	345	Arnold	Pine River	150	New 345 kV Line	424.5	424.5
New	Line	345	Livingston	Pine River	82.5	New 345 kV Line	233.5	233.5
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4

Transmission Idea MI-13								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-14								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Third Line	64	New tie line to Ontario	181.1	181.1
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-15

Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	HVDC/345/230	Third Line			New substation in Ontario with 230 kV AC/DC/ 345 kV AC conversion	372.1	372.1
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Pine River	48	New 345 kV Line	135.8	135.8
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Transmission Idea MI-16								
Adjustment Type	Facility Type	Voltage (kV)	From Substation	To Substation	Estimated Length (Miles)	Description	IESO Tie Cost (M$)	Radial Generator Cost (M$)
New	Substation	345/138	Pine River			New substation or switching station at Pine River	15.4	15.4
New	Substation	345	Hiawatha			New substation or switching station at Hiawatha	15.4	15.4
New	Substation	345	McGulpin			New substation or switching station at McGulpin	15.4	15.4
New	Substation	345	Third Line			New substation in Ontario	11.8	11.8
Reconfigure	Substation	69	Pine River			Move connections of the Pine River - Straights 69 kV lines to the 138 kV switching station and operate at 138 kV.	0.2	0.2
New	Transformer	345/230	Third Line			Tie the new voltage to the local 230 kV system	8.5	8.5
New	Transformer	345/138	Hiawatha			New transformer	7.5	7.5
New	Transformer	345/138	McGulpin			New transformer	7.5	7.5
New	Transformer	345/138	Pine River			New transformer	7.5	7.5
New	Transformer	138/69	Pine River			New transformer to tie to the local 69 kV system	7.5	7.5
New	Line	345	Arnold	Hiawatha	102	New 345 kV Line	288.7	288.7
New	Line	345	Hiawatha	Pine River	48	New 345 kV Line	135.8	135.8
New	Line	345	Livingston	McGulpin	52	New 345 kV Line	147.2	147.2
New	Line	345	McGulpin	Pine River	30.5	New 345 kV Line	86.3	86.3
New	Line	345	Third Line	Pine River	33	New tie line to Ontario	93.4	93.4
Rebuild	Line	138	Hiawatha	Pine River	48	Rebuild the 69 kV line from Hiawatha to Pine River to 138 kV and tie to the new station at Pine River.	59.5	59.5

Study of Export Capabilities of the Sault Ste. Marie Transmission System

Prepared for MISO by Transmission Integration

August, 2017

Appendix D

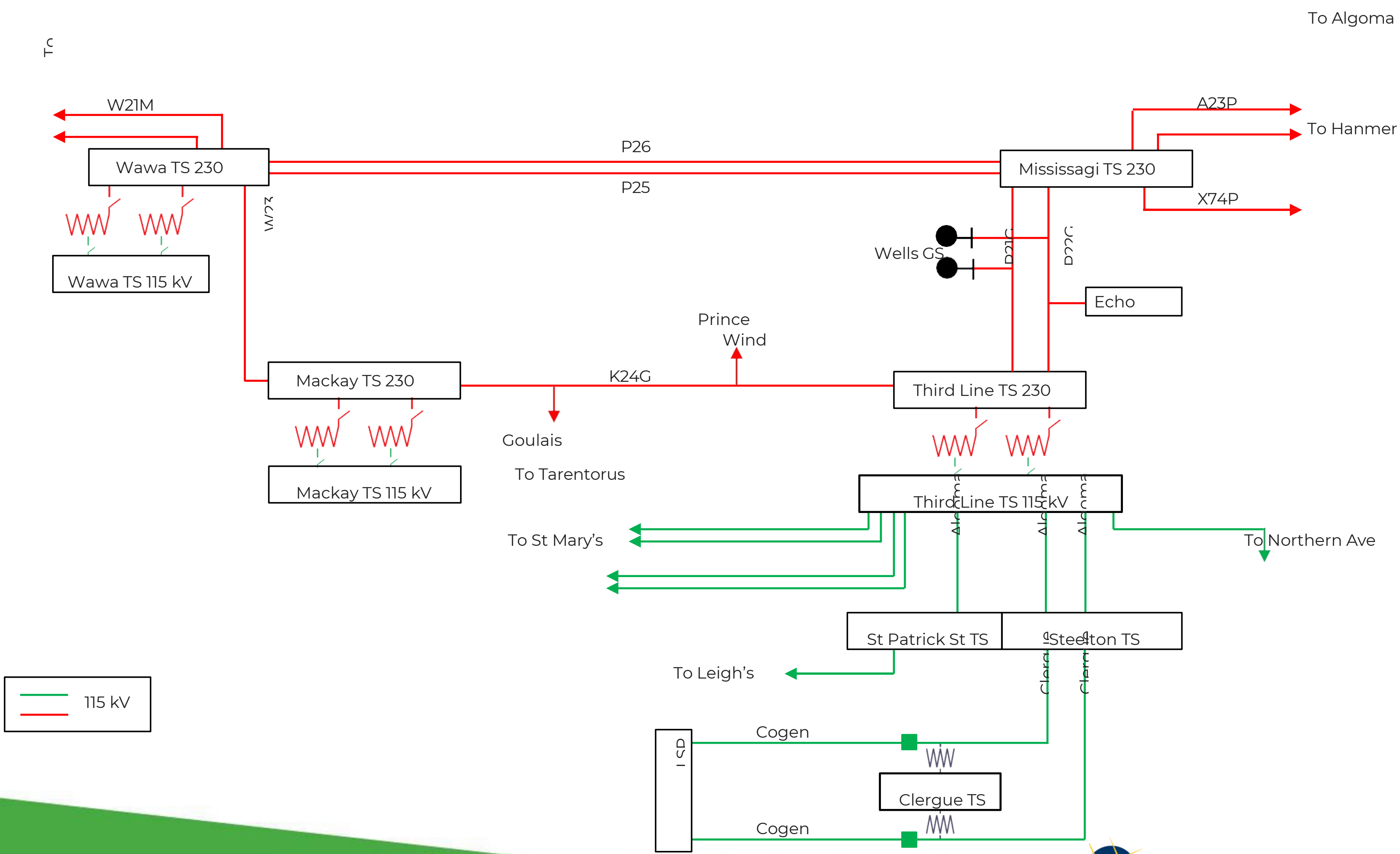
Connecting Today.
Powering Tomorrow.

Background

- The IESO carried out a high level study to assess the capability of the transmission system in the Sault Ste. Marie ("SSM") area to export capacity to Michigan
- The study was completed to support MISO's exploratory study of options to meet capacity needs in Michigan
- The IESO's study assumes the export would occur via a new intertie constructed under the St Mary's river; the intertie is one of various options MISO's study will consider

- The study used the following assumptions and simplifications:
  - The new intertie will either be:
    - Connected to a new bus near Clergue TS (115 kV)
    - Require a new 230 kV line from near Clergue TS to Third Line TS (230 kV)
  - Exports were modeled as a load with 0.9 lagging power factor
  - Only active and contracted local generation facilities were considered available to supply local load and exports
  - No margin was considered for local electrical load growth in the SSM region (i.e. any long term export deal would also need to consider future load growth in the SSM area)
  - Remedial action schemes or emergency operational tools were not considered in the study

Single Line Diagram of the Existing SSM Transmission System



Summary of Key Findings

- Export capability was assessed for both summer and winter conditions with the benefits of certain system enhancements considered:

Scenario	Export Capability[1]		Description
	Summer	Winter	
Without system enhancements	50 MW	25 MW	Limited by thermal ratings on the local, 115 kV transmission system
With system enhancements	125 MW	75 MW	Required enhancements: - Mitigation of thermal constraints on the 115 kV system - Reconfiguration of 230 kV circuits supplying the SSM system[2] Limited by Third Line TS autotransformers and the thermal rating of 115 kV circuits connecting Steelton/Patrick St. TS and Clergue TS
With system enhancements	325 MW	275 MW	Required enhancements: - New 230 kV circuit from Clergue TS to Third Line TS (approximately 5 km) - Reconfiguration of 230 kV circuits supplying the SSM system[2] - Additional voltage control facilities Limited by thermal ratings of 230 kV circuits supplying SSM system

[1] The assessed capability is based on current system conditions and is provide for the purpose of MISO's exploratory study. It is subject to change based on future system conditions.

[2] Currently these circuits share a number of towers, they would need to separated to achieve the

Conclusions & Next Steps

- **Based on the evaluated system conditions, the Sault Ste. Marie transmission system can accommodate:**
  - A 50 MW (summer) or 25 MW (winter) export from a new 115 kV bus near Clergue TS before the 115kV system becomes limiting
  - A 125 MW (summer) or 75 MW (winter) export from a 115 kV bus near Clergue TS, assuming:
    - Thermal issues on the 115 kV were mitigated
    - The 230 kV circuits supplying SSM were reconfigured
  - A 325 MW (summer) or 275 MW (winter) export from a 230 kV bus near Clergue TS, assuming:
    - A new 230 kV line is constructed from Third Line TS to near Clergue TS
    - 230 kV circuits supplying SSM were reconfigured
    - Voltage control facilities are installed to maintain adequate voltage at Third Line TS under peak load and export conditions
- **More detailed studies and analysis would be required to assess:**
  - Effect of local electrical load growth on export capabilities
  - Cost and full scope of the required system enhancements
  - Level of reliability or "firmness" required for power exports

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Appendix I: UP Generation Integration Screening Study

Upper Peninsula Generation Integration Screening Study

September 2016

ATC voluntarily performed a high level, steady-state screening of transmission facilities in Michigan's Upper Peninsula. This was done to assist generation developers with the preliminary identification of potential locations where existing transmission facilities may be able to accommodate the addition of new and/or additional generation capacity. All potential locations were screened for single contingency steady-state limitations. Locations that could not accommodate generation for a single contingency were removed from the Tables that were produced through this effort. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted. ATC may choose to perform similar screening studies of other portions of its footprint in the future, as system conditions and circumstances warrant.

Additional steady state, multiple contingency analysis was performed for locations that appeared to be capable of hosting 100 MW or more of generation under steady state, single contingency conditions. The multiple contingency analysis resulted in reduced generation capacity from the single contingency screen being indicated for some locations. Other locations could not accommodate any new generation under multiple contingency conditions and, as such, were removed from the Tables. ATC has not performed any analysis to identify the scope or cost of work to eliminate the limit(s) that were identified for any of the contingencies that were noted.

ATC's screening did not include any stability analysis. Previous studies in the UP have identified sensitivity to stability issues. Since different types of generating units may have substantially different stability performance characteristics, a stability analysis would not be generally applicable. Furthermore, this study did not consider the number or size of units necessary to be a replacement for Presque Isle Power Plant. Finally, the study analyzed only one potential generation site at a time and, as such, the results are not necessarily additive.

The Tables that follow below identify the location, screening results and the U.P. sub-zone where existing transmission facility is located. The attached map is divided into six sub zones for ease in finding the locations identified in the Tables. Tables 1 illustrates the results of the multiple contingency analysis. Table 2 provides the results of the single contingency analysis sorted by sub-zone.

Additional disclaimers: This was a high level screening study using a single steady-state model and a particular set of assumptions, as described herein. The study results listed in the Tables below may not be indicative of the results that would be produced via the MISO Tariff Attachment X Generation Interconnection process. System stability, both angular and voltage, were not considered in this screening study. ATC makes no representations, either expressed or implied, that the scope of the interconnection facilities or transmission upgrades required to connect generation at these sites would be minimal, or even feasible. Single contingency screening results do not reflect any possible reductions required for multiple contingencies. The analysis considered 69kV, 138kV and 345kV nodes in the power flow model, but did not consider actual bus configuration or the existence of buses for constructability at the locations that were studied. Corresponding interconnection facilities and transmission upgrades will be determined by the MISO Tariff Attachment X process. This non-binding, voluntary study is presented for informational purposes only and ATC makes no guarantee or warranty that the information presented herein is accurate or complete.

Additional Steady- State Analysis Base Assumptions

Presque Isle Generating Plant Output: 0 MW

Interconnection with the City of Marquette: 0 MW

interchange Mackinac HVDC flow modeled as: 20 MW North

to South White Pine Generating Plant Output: 0 MW

Empire Mine Load: 0 MW

Preliminary Results with Multiple Contingency Screen

Table 1

Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
Atlantic	69kV	77	1	Multiple
M-38	138kV	75	1	Multiple
Presque Isle	138kV	274	3	Multiple
National	138kV	260	3	Multiple
Empire	138kV	240	3	Multiple
Freeman	138kV	149	3	Multiple
Big Bay	138kV	136	3	Multiple
Tilden	138kV	124	3	Multiple
Barnum	138kV	107	3	Multiple
North Lake	138kV	107	3	Multiple
Perch Lake	138kV	103	3	Multiple

Preliminary Results Using Single Contingency Screen				
Table 2				
Location	Voltage	Potential Generation Amount (MW)	Sub Zone	Contingency Screen
M-38	69kV	68	1	Single
Elevation St.	69kV	61	1	Single
Winona	69kV	60	1	Single
Atlantic	138kV	59	1	Single
Winona	138kV	58	1	Single
Boston	69kV	56	1	Single
Osceola	69kV	56	1	Single
Mass	69kV	50	1	Single
Henry St.	69kV	48	1	Single
MTU	69kV	48	1	Single
Lake Mine	69kV	39	1	Single
Toivola	69kV	39	1	Single
Ontonagon	69kV	37	1	Single
Ontonagan	138kV	34	1	Single
Portage	69kV	33	1	Single
White Pine Mine	69kV	33	1	Single
Rockland	69kV	32	1	Single
White Pine Village	69kV	32	1	Single
Baraga	69kV	31	1	Single
L'Anse	69kV	30	1	Single
UPSCO	69kV	27	1	Single
Victoria	69kV	26	1	Single
Keweenaw	69kV	21	1	Single
Twin Lakes	138kV	77	2	Single
Aspen	69kV	70	2	Single
Iron Grove	69kV	55	2	Single
Lakota Rd.	138kV	47	2	Single
Strawberry Hill	69kV	41	2	Single
Crystal Falls	69kV	40	2	Single
Peavy Falls	69kV	35	2	Single
Lincoln	69kV	32	2	Single
Florence	69kV	30	2	Single
Lakehead	69kV	25	2	Single
Pine	69kV	22	2	Single
Conover	69kV	20	2	Single
Lakota Rd.	69kV	20	2	Single
Michigamme	69kV	16	2	Single

Preliminary Results Using Single Contingency Screen Table 2 (Continued)				
Location	**Voltage**	**Potential Generation Amount (MW)**	**Sub Zone**	**Contingency Screen**
Bruce Crossing	69kV	15	2	Single
Land O Lakes	69kV	15	2	Single
Watersmeet	69kV	13	2	Single
Forsyth	69kV	93	3	Single
North Lake	69kV	60	3	Single
Barnum	69kV	52	3	Single
Alger Delta	69kV	46	3	Single
Chatham	69kV	46	3	Single
Munising	69kV	46	3	Single
Forest Lake	69kV	45	3	Single
AD Hiawatha	69kV	44	3	Single
Mineral Proc.	69kV	43	3	Single
Munising	138kV	40	3	Single
Gwinn	69kV	39	3	Single
Timber Products	69kV	29	3	Single
Greenstone	69kV	25	3	Single
Sawyer	69kV	21	3	Single
MTF	69kV	13	3	Single
Perch Lake	69kV	13	3	Single
Randville	69kV	73	4	Single
Watson	69kV	51	4	Single
Mountain	69kV	48	4	Single
Harris	69kV	36	4	Single
Sagola	69kV	34	4	Single
Old Mead Rd.	69kV	86	5	Single
Lakehead Rapid River	69kV	56	5	Single
North Bluff	69kV	53	5	Single
Masonville	69kV	52	5	Single
West Side	69kV	51	5	Single
Bay View	69kV	50	5	Single
Cornell	69kV	48	5	Single
Escanaba	69kV	45	5	Single
Gladstone	69kV	45	5	Single
Blaney Park	69kV	84	6	Single
Engadine	69kV	84	6	Single
Valley	69kV	83	6	Single
Gould City	69kV	82	6	Single
Curtis	69kV	81	6	Single
Manistique	69kV	73	6	Single

Preliminary Results Using Single Contingency Screen				
Table 2 (Continued)				
Location	**Voltage**	**Potential Generation Amount (MW)**	**Sub Zone**	**Contingency Screen**
Glen Jenks	69kV	59	6	Single
3 Mile	69kV	54	6	Single
9 Mile	69kV	54	6	Single
Newberry	69kV	49	6	Single
Sault	69kV	49	6	Single
Louisiana Pacific	69kV	48	6	Single
NBHSPL 69	69kV	48	6	Single
Newberry Village	69kV	48	6	Single
Roberts	69kV	47	6	Single
Portage St	69kV	46	6	Single
Tone	69kV	42	6	Single
Kincheloe	69kV	41	6	Single
Rudyard	69kV	41	6	Single
Eckerman	69kV	39	6	Single
Hulbert	69kV	39	6	Single
MI Limestone	69kV	37	6	Single
Raco	69kV	37	6	Single
Rexton	69kV	36	6	Single
Rockview	69kV	36	6	Single
Brimley	69kV	35	6	Single
Trout Lake	69kV	34	6	Single
Pine Grove	69kV	33	6	Single
Detour	69kV	32	6	Single
Goetzville	69kV	32	6	Single
Magazine	69kV	32	6	Single
Pickford	69kV	32	6	Single
Seney	69kV	31	6	Single
Talentino	69kV	31	6	Single
Dafter	69kV	27	6	Single
St. Ignace	69kV	26	6	Single
MLQ	69kV	25	6	Single

Appendix J: Biomass with Tire Derived Fuel Emissions Study

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Technical Memo

SUBJECT: L'Anse Warden Electric Company (LWEC): CO Emissions

DATE: September 13, 2024 PROJECT NO.: 240888

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Introduction

During a recent tour of the LWEC site, members of the Michigan Public Service Commission (MPSC) asked about carbon monoxide (CO) emissions from the boiler, especially as CO emissions vary when burning biomass compared to tire-derived fuel (TDF). Completing a comparison at LWEC is difficult as the plant always burns a fuel blend that includes wood chips, creosote-derived wood (like railroad ties or utility poles), and other forms of biomass along with TDF. One fuel is never burned exclusively for any period of time. Information used in permitting this and other biomass facilities was used to explain how CO emissions vary when burning biomass. Information on CO emissions from LWEC are also provided.

Background

When reviewing permits for biomass-fired boilers as well as Federal Rules that affect biomass-fired boilers, it is clear that USEPA anticipates higher CO emissions when burning biomass. CO BACT Analyses are often required when permitting a biomass-fired boiler. A list of biomass-fired boilers in Michigan and their CO emission limit is provided in Attachment 1. This table indicates that the 0.30 lb/mmbtu per hour (averaged over 24 hours) is one of the lower CO permit limits for biomass-fired boilers in Michigan. Though it should also be noted that changes in the legislation associated with defining "renewable energy" have forced the closure of several plants on that list.

In addition to CO BACT Analyses, the Industrial, Commercial, and Institutional Boilers and Process Heaters: National Emission Standards for Hazardous Air Pollutants (NESHAP) for Major Sources includes higher CO limits for biomass boilers than for boilers firing fossil fuels as indicated in the graphic below:[1].

Type of Boiler	Pollutant	Limit/Averaging Time
Stokers/sloped grate/others designed to burn wet biomass fuel	CO (or CO CEMS)	1,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (720 ppm by volume on a dry basis corrected to 3-percent oxygen 30-day rolling average)
Stokers/sloped grate/others designed to burn kiln-dried biomass fuel	CO	460 ppm by volume on a dry basis corrected to 3-percent oxygen
Fluidized bed units designed to burn biomass/bio-based solid	CO	470 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (310 ppm by volume on a dry basis corrected to 3-percent oxygen, 30-day rolling average)
Suspension burners designed to burn biomass/bio-based solid	CO	2,400 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (2,000 ppm by volume on a dry basis corrected to 3-percent oxygen, 10-day rolling average)
Dutch Ovens/Pile burners designed to burn biomass/bio-based solid	CO	770 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (520 ppm by volume on a dry basis corrected to 3-percent oxygen, 10-day rolling average)
Fuel cell units designed to burn biomass/bio-based solid	CO	1,100 ppm by volume on a dry basis corrected to 3-percent oxygen
Hybrid suspension grate units designed to burn biomass/bio-based solid	CO (or CEMS)	3,500 ppm by volume on a dry basis corrected to 3-percent oxygen, 3-run average; or (900 ppm by volume on a dry basis corrected to 3-percent oxygen, 30-day rolling average)

Graphic 1. NESHAP CO Emission Limits for Industrial Boilers and Process Heaters at Major Sources

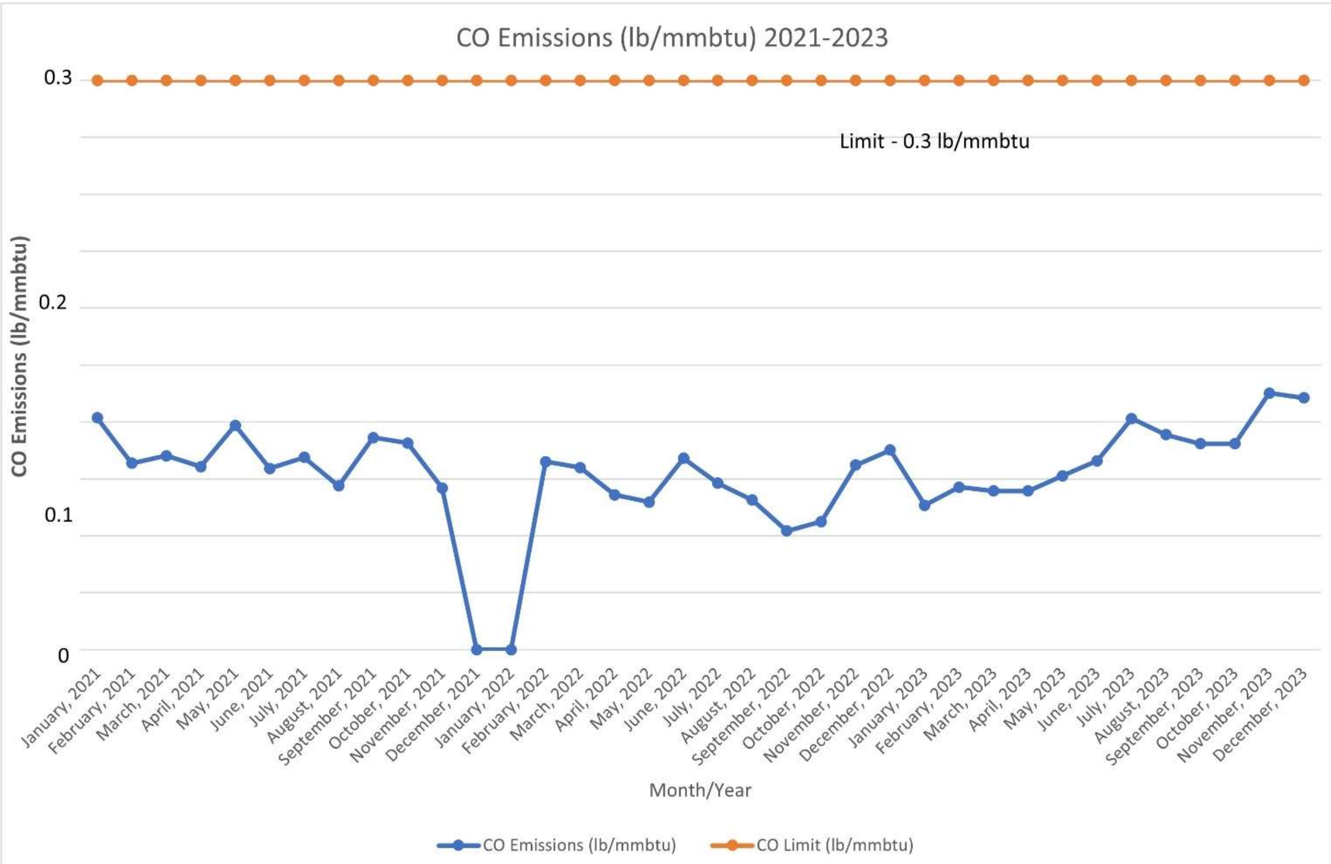
Wet biomass fuels can be more variable than traditional fuels and may not burn as evenly. This variability can result in higher CO emissions. Commentors explained that wet biomass fuels vary depending on the type of fuel and the weather. Higher moisture contents that occur with wet weather make the fuel burn more unevenly. Wood residue can also vary in size and type, which can contribute to higher CO emissions. During the winter and spring, biomass fuels can be high in moisture meaning that additional fuels will have to be burned to make up the load lost to energy expending in evaporating the additional moisture. The TDF does not absorb water and is unaffected

[1] It should be noted that CO is used as a surrogate for volatile organic hazardous air pollutant (HAP) emissions. CO is not a HAP.

by wet or frozen conditions. LWEC must carefully manage its fuel blend to ensure that the boiler heat input is adequate to accommodate additional moisture during these times.

CO Emissions at LWEC

Because LWEC has a continuous emissions monitoring system (CEMS) for CO, the plant is able to provide monthly CO emissions averages from 2021 through 2023, which are summarized below:



Graphic 2. CO Emissions 2021-2023

It should be noted that the plant went through a major outage during December, 2021 through January, 2022, and no CO emissions were generated. This chart indicates that there is some variability in CO emissions during the year. When the wood is cold and wet, the CO emissions tend to be higher. Adding TDF or other fuels which are not as sensitive to temperature and moisture will allow for more complete combustion and lower CO emissions. Because the plant uses a blend of fuels, its difficult to use plant CO emissions data to indicate the affects of the different fuels, operating conditions and weather on the CO emissions. Plant operators blend fuels and adjust boiler load to ensure compliance with the various emission limits, including the CO emission limit.

The MPSC specifically requested CO emissions when the plant was burning TDF as compared to when the plant is burning a fuel mix that does not include TDF. Because a number of variables affect CO emissions when burning biomass, and operating conditions change from day to day, a comparison is difficult. Though in one instance, no TDF was included in a fuel blend where the boiler operated at a similar load and weather just a week earlier. In that case, CO emissions on May 15, 2022, would be expected to be similar to emissions on May 22, 2022. But they are not. On May 15, 2022, the fuel blend included TDF and CO emissions were almost 20% higher.

	Daily Generation		Fuel			Emissions Daily Average			
Date	Steam Flow	Gross MW	RR Ties	Wood Chips	TDF	02%	Opacity %	CO PPM	CO lb/mmBTU
05/15/22	3,783,900	406,350	161.96	277.92	26.91	9.8	2	64.1	0.084
05/22/22	2,727,200	296,980	157.06	361.32	0.00	12.4	2.6	58.5	0.100

Graphic 3. CO Emissions While Burning TDF and Without TDF

Because of the number of variables that affect CO emissions, a more detailed analysis might not provide more helpful information.

Carbon Footprint

Biomass is considered an alternative energy source to fossil fuels. While burning both fossil fuels and biomass release CO_2, source plants for biomass capture almost as much CO_2 through photosynthesis as biomass releases when burned, which makes biomass a carbon neutral source. [2] Burning biomass can also reduce the amount of material disposed of in landfills. In addition, using forest biomass for energy results in a “carbon debt” when burning biomass releases CO_2 into the atmosphere. This debt can be repaid when forests grow back. Using biomass as a fuel also promotes sustainable forest management. When wood residues are left to decompose or burn in open-air fires, harmful pollutants are released into the air. Collecting the wood and using it as fuel encourages sustainable forest management practices including selective logging and reforestation. These sustainable forest management practices can be funded through the sale of this wood (which is often waste wood) and can be an important part of preventing forest fires.

[2] Source: U.S. Energy Information Administration, *Monthly Energy Review*, Environment section note; see Note 2: Accounting for carbon dioxide emissions from biomass energy combustion.

Attachment 1 - Summary of Michigan Biomass-fired Boilers CO Limits

L'Anse Warden Electric Company CO Emissions Information

SRN	Facility	Location	Year Permitted	Rating (mmbtu/hr)	CO limit	Units	Averaging Time
B4260	L'Anse Warden Electric Company	L'Anse. Michigan	2008 (modified)	324	0.3	lb/mmbtu	24 hr
			BACT Limit		97.2	lb/hr	Hourly
N0890	National Energy	Lincoln. Michigan	1986	230	0.25	lb/mmbtu	24 hr
			BACT Limit		57.5	lb/hr	24-hr
N1160	National Energy	McBain, Michigan	1986	230	0.25	lb/mmbtu	24 hr
			BACT Limit		57.5	lb/hr	24-hr
N1266	Hillman Power Company	Hillman, Michigan	1985	300	120	lb/hr	24-hr
			BACT Limit		140	lb/hr (incl SS)	24-hr
N1395	Cadillac Renewable Energy	Cadillac, Michigan	1993	523	0.4	lb/mmbtu	24-hr
			BACT Limit		209.2	lbhr	24-h4
N2388	Grayling Generating Station, LP	Grayling, Michigan	1992	523	0.4	lb/mmbtu	24-hr
			BACT Limit		209.2	lb/hr	24-hr
N3570	Genessee Power Station LP	Flint, Michigan	1992/2011	523	0.35	lb/mmbtu	24-hr
			BACT Limit		183.1	lb/hr	24-hr

* The Hillman limit is equivalent to 0.47 lb/mmbtu.

Appendix K: UP Carbon Sequestration Feasibility Study

Upper Peninsula Geology/Hydrogeology and Feasibility of Carbon Sequestration

Background

On May 24, 2024, staff from the Michigan Department of Environment, Great Lakes, and Energy (EGLE), Oil, Gas, and Minerals Division (OGMD) met with staff from the Michigan Public Service Commission (MPSC), Energy Resources Division (ERD) to discuss the potential feasibility of carbon sequestration within the geologic formations within the Upper Peninsula through utilization of Class VI Underground Injection Control (UIC) wells.

The United States Environmental Protection Agency (US EPA) administers the federal UIC program, and it is currently comprised of six classes of injection wells. Modern injection well requirements date back to 1974 with the passage of the Safe Drinking Water Act (SDWA). Since that time there have been significant amendments to the SDWA and UIC rules (on both the federal and state levels) regarding the construction and operation requirements of injection wells to ensure that groundwater, the environment, and public health and safety are protected. Class VI wells are a relatively new category under the UIC program. There are currently no Class VI Carbon Sequestration Wells in Michigan and about a dozen or so in the United States. Wells of this type are currently dually permitted by the OGMD and the US EPA. Michigan would permit a Carbon Sequestration Well under the Part 625 Mineral Well program as a Waste Disposal Well. However, EGLE is pursuing Class VI delegated authority and expects that there will be statutory framework and associated administrative rules in the near future to address these types of wells in Michigan under a new type of program. Class VI wells inject carbon dioxide (CO_2) which is captured and stored underground where it remains geologically sequestered permanently. Wells of this type can reduce the amount of greenhouse gas emissions that are added to the atmosphere and would be used by power generation sectors and other industrial sources. Paramount to all federal and state UIC regulations is that considerations of a variety of measures are incorporated to assure that injection activities will not endanger Underground Sources of Drinking Water (USDWs). USDWs are defined as an aquifer or portion of an aquifer that currently supplies a public water supply system or an aquifer or portion of an aquifer that contains sufficient quantity to supply a public water system and is currently being used for human consumption and contains fewer than 10,000 mg/L of total dissolved solids. For more information about injection wells in Michigan please refer to the OGMD website.

Geology and Hydrogeology

The Paleozoic-aged Michigan Basin is comprised of a thick package of layered sedimentary formations (sandstones, shales, limestones, evaporate deposits, etc.) that are conducive to extraction (oil and gas) and injection (brine and waste disposal) due to the higher porosity and permeability of these formations and the presence of continuous confining zones. A confining zone is a sufficiently thick interval of rock that serves as a barrier to the upward migration of oil, gas, and injectate and is required by the US EPA and EGLE above injection intervals within bedrock formations. The Michigan Basin sedimentary formations are present throughout the entire lower peninsula and are also found in the central and eastern portions of the upper peninsula. While the basin formations of the upper and lower peninsulas are geologically correlative, they are distinctly different when considering the presence of USDWs. For example, groundwater quality within the basin formations of the lower peninsula changes with from freshwater to brackish and high-salinity brines fairly rapidly with depth. A US Geological Survey investigation from 1996 delineates the freshwater and saline-water interface within a 22,000-square-mile area of the central Michigan Basin (*Westjohn and Weaver, 1996*). The investigation found that this interface is located between approx. 300 and 800 feet above mean sea level (ft amsl) across the lower peninsula. Saline-water (many times orders of magnitude greater than 10,000 mg/L that defines a USDW) is present below this interface and the permitting of injection wells could be feasible given all other permitting requirements have been met.

However, in the Upper Peninsula, there has been observed water supply wells that were drilled deep into the Michigan Basin Paleozoic sedimentary formations near Manistique, Michigan and remain within USDWs (up to 2,030 feet below the ground surface, or more than -1,380 ft amsl). See the Department of Natural Resources *Thompson Fish Hatchery Well ID No. 77000000403* record for more information. For reference, the surface of Lake Michigan is approx. 578 ft amsl, and the surface of Lake Superior is approx. 600 ft amsl.

The central and western portions of the Upper Peninsula are underlain by bedrock that is Precambrian in age and much older than the Paleozoic rocks of the Michigan Basin. These geologic formations are crystalline igneous, volcanic and metamorphosed rocks as well as sedimentary rocks. Some of these Precambrian sedimentary formations have higher transmissivities, like the Jacobsville Sandstone, and are commonly used as a freshwater aquifer. Other formations may exhibit structural features, such as fractures, that may be utilized as USDWs but typically have much lower yields. In a report published by the US Geological Survey that details hydrogeologic conditions by county for the State of Michigan (*Apple and Reeves, 2007*), some central and western upper peninsula counties report the use of the Precambrian bedrock as the source for drinking water wells for up to 75% of the wells documented in EGLE's Wellogic Database. This database contains information for different types of water supply wells for single-home residential use to municipal wells serving entire communities.

Feasibility Analysis

Generally, the geology and hydrology of the Upper Peninsula makes the permitting of Class VI wells difficult. The presence of deep USDWs in the Paleozoic formations of the central and eastern portions of the upper peninsula would require exploration more than 2,000 feet below ground surface to determine where the freshwater/saline-water interface is located. In fact, the Amoco Production Company completed a permitted test well in Alger County that encountered sandstone formations down to approx. 6,500 feet below ground surface (see the *St. Amour 1-29R test well log, Permit #021-871-202* for more information). Additionally, the geophysical logs from this test well indicate that no rock formation encountered during drilling is appropriate for use as a confining zone. This means that the demonstration must still be made that the injection of CO_2 would occur beneath the lowest USDW zone with a sufficiently thick confining layer.

Some of the western Upper Peninsula Precambrian geologic formations may have sufficient permeability and porosity for injection, such as the Precambrian sedimentary formations, while other crystalline formations may have carbon sequestration capacity within the structural features such as fractures, faults, etc. However, determining the feasibility is a challenge without additional significant exploration to confirm that these formations are conducive to injection with structural features that are regional and interconnected providing volume capacity, and/or exhibit sufficient permeabilities and porosities. The presence of confining zones separating the USDWs of the upper peninsula from the zone of injection is also of great importance and these types of geologic formations may not be present in sufficient lateral and vertical extents in either the Paleozoic or Precambrian geologic formations.

References

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Safe Drinking Water Act, Public Law 93-523
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Configuration of Freshwater/Saline-Water Interface and Geologic Controls on Distribution of Freshwater in a Regional Aquifer System, Central Lower Peninsula of Michigan; 1996, D.B. Westjohn and T.L. Weaver

Water Well Log of Department of Natural Resources Thompson Fish Hatchery Well ID No. 77000000403

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