STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to implement the provisions of Sections 6t(1) of Public Act 231 of 2023.	)	Case No. U-21867
In the matter, on the Commission's own motion, to implement the provisions of Sections 6t(1), (5), (7), (8), (12), and (15) of Public Act 231 of 2023 and Sections 3, 5, 7, 22, 28, 51, 101, and 103 of Public Act 235 of 2023.	)	Case No. U-21570

At the December 18, 2025 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Daniel C. Scripps, Chair
Hon. Katherine L. Peretick Commissioner
Hon. Shaquila Myers, Commissioner

ORDER

Background

On November 28, 2023, Governor Gretchen Whitmer signed into law Public Act 231 of 2023 (Act 231), which, in part, amended Section 6t of Public Act 341 of 2016 (Act 341). The amendments in Act 231 became effective as of February 13, 2024.

Section 6t of Act 231, MCL 460.6t, amended Act 341 and states in relevant part that:

> (1) The commission shall, by August 31, 2025, and every 4 years thereafter, commence a proceeding and, in consultation with the Department of Environment, Great Lakes, and Energy, and other interested parties, do all of the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state.

(b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment must expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills.

(c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.

(d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.

(e) Identify any required planning reserve margins and local clearing requirements in areas of this state.

(f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:

(i) Any required planning reserve margins and local clearing requirements.

(ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

(iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, projected load impact due to electrification, and projected load management and demand response savings.

(iv) Any regional infrastructure limitations in this state.

(v) The projected costs of different types of technologies and fuel used for electric generation.

(g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios or assumptions.

(h) Publish a copy of the proposed modeling scenarios and assumptions to be used in integrated resource plans on the commission’s website.

> (i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.
>
> (j) Conduct an assessment of the potential for electrification of transportation, buildings, and industries consistent with economy-wide elimination of greenhouse gas emissions in this state, based on what is economically and technically feasible, as well as what is reasonably achievable.
>
> (k) Identify environmental justice communities.

Section 6t(2) of Act 231 provides that:

> [a] proceeding commenced under subsection (1) must be completed within 120 days, and is not a contested case under chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.288. The determination of the modeling assumptions for integrated resource plans made under subsection (1) is not considered a final order for purposes of judicial review. The determinations made under subsection (1) are only subject to judicial review as part of the final commission order approving an integrated resource plan under this section.

MCL 460.6t(2). Although Act 231 amended Act 341, Section 6t(3) was not changed and states that the Commission "shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission." MCL 460.6t(3).

Consistent with Sections (1) and (2) of Act 341, on November 21, 2017, in Case No. U-18418 (November 21 order), the Commission approved the Michigan Integrated Resource Planning Parameters (MIRPP). The MIRPP states that "[e]ach electric utility whose rates are regulated by the Commission shall demonstrate compliance with the Michigan Integrated Resource Planning Parameters as a condition of Commission approval of its respective integrated resource plan pursuant to MCL 460.6t(3)." November 21 order, p. 88.

On August 20, 2020, the Commission opened the docket in Case No. U-20633 (August 20 order) and directed the Commission Staff (Staff) to begin outreach through a series of sessions

with interested persons to research best practices in integrated resource and distribution planning. August 20 order, p. 5. The Commission's directives included "[i]dentifying potential revisions to the Commission-approved IRP [integrated resource plan] modeling parameters or the filing requirements to better accommodate transmission alternatives in IRPs in preparation for the next formal review of the Michigan IRP Planning Parameters expected to take place in 2022." *Id*., pp. 3-4. Accordingly, the Commission initiated a collaborative to review and discuss improvements and ways to better align integrated resource planning and distribution planning, directed the Staff to coordinate with the Michigan Department of Environment, Great Lakes, and Energy (EGLE) on the inclusion of public health and environmental justice consideration in future IRPs, and directed the Staff to file a May 27, 2021 report (May 27 report) outlining its findings and recommendations. *Id*., p. 5.

On September 24, 2021, the Commission issued an order (September 24 order) accepting the Staff's May 27 report and adopting the recommendations made therein. September 24 order, p. 31. The Commission directed the Staff to create a redline version of the MIRPP for review by interested persons in the MI Power Grid Advanced Planning Phase II process and to distribute this document to interested persons no later than December 22, 2021. *Id*. The Commission directed the Staff to file its final draft of the MIRPP on June 30, 2022, in a new docket to be opened on the Commission's own motion to update the MIRPP. *Id*., p. 32.

On June 30, 2022, the Staff filed a draft MIRPP in Case No. U-21219 and the Commission provided interested persons an opportunity to comment on the draft MIRPP. *See*, July 7, 2022 order in Case No. U-21219. Following two in-person hearings and a comment period, the Commission issued an order in Case No. U-21219 on October 10, 2022 (October 10 order) that

adopted the final MIRPP and required utilities whose rates are regulated by the Commission to model the adopted scenarios and sensitivities as part of their IRP filings. October 10 order, p. 41.

Act 231, which amended Act 341, includes several updates to the IRP statute, including updates to the planning parameters, plan filing requirements, and considerations the Commission must review in its evaluation of the plan. MCL 460.6t(1) and (2). Act 231 requires the planning parameters to be updated in 2025. *Id*. Additionally, in an order issued in Case No. U-21570 on February 8, 2024 (February 8 order), the Commission initiated Case No. U-21570 to begin implementing IRP-related provisions in Public Act 235 of 2023 (Act 235), MCL 460.1001 *et seq*. The February 8 order also directed the Staff to commence studies for energy waste reduction (EWR), demand response (DR), and the electrification of transportation, buildings, and industries as required by MCL 460.6t(1)(a), (b), and (j). February 8 order, p. 6. Additionally, the February 8 order directed the Staff to:

> create a page on the Commission's website[1] that, among other things, will provide a redline version of the Michigan Integrated Resource Planning Parameters (MIRPP) and Integrated Resource Plan (IRP) Filing Requirements that will be updated pursuant to the requirements of Acts 231 and 235, as well as provide a straw proposal related to providing formats and guidelines for investor-owned utilities, municipal electric utilities, cooperative electric utilities, and alternative electric suppliers to submit a clean energy plan pursuant to the requirements of Act 235.

Id. The Commission noted that "there is potential overlap between many of the issues to be considered as part of the MIRPP and IRP Filing Requirements updates and how these same or similar issues are addressed in other Commission proceedings." *Id*., p. 7. Consistent with the February 8 order, the Staff posted a redline of the MIRPP and IRP filing requirements and held

[1] The Staff-created web page for the 2023 energy legislation can be found at https://www.michigan.gov/mpsc/commission/workgroups/2023-energy-legislation/integrated-resource-planning-process (last accessed December 18, 2025).

two engagement meetings to consider all comments received as part of the engagement process for inclusion in the final draft of the MIRPP and IRP filing requirements, along with the clean energy plan (CEP) filing requirements for the various electric providers in Michigan.

On August 15, 2025, the Staff posted to the dedicated website the final draft of the MIRPP and IRP filing requirements. Additionally, the Staff posted draft CEP filing requirements for rate-regulated electric utilities, draft CEP filing requirements for Michigan municipalities, and draft CEP filing requirements for Michigan electric cooperatives and alternative electric suppliers. All draft documents were also posted to this case docket.

On August 21, 2025, the Commission issued an order in this docket (August 21 order) setting two public hearings to provide interested persons with additional opportunities to comment on the final draft of the MIRPP and IRP filing requirements, along with the three draft CEP filing requirements documents. The hearings provided information about the final draft of the MIRPP and IRP filing requirements, and draft CEP filing requirements, solicited public comment on the final draft of the MIRPP and IRP filing requirements and draft CEP filing requirements, and addressed questions about the MIRPP, IRP, and CEP review process.

On October 20, 2025, the Staff filed in this docket the 2025 Energy Waste Reduction, Demand Response, and Efficient Electrification Statewide Potential Study (Potential Studies). According to the Staff:

> [t]he 2025 Efficient Electrification Potential Study was commissioned to determine the Technical, Economic, and Achievable potential for electrification of fossil fuel-consuming end-uses in Michigan, in conjunction with parallel studies examining the potential for energy efficiency, demand response, and vehicle electrification. This study evaluated a wide range of efficient electrification technologies and their application to the building stock of Michigan in the 2026-2045 timeframe. A bottom-up, building stock driven model was the primary method used to evaluate electrification potential, but top-down methods were also integrated for specific areas where granular data was lacking, namely for new construction and in the industrial sector.

Executive Summary, Potential Studies, p. ii. The Potential Studies is a five-part report, including appendices for each part, and prepared as: Volume I: Building and Process Electrification; Volume II: Transportation Electrification; Volume III: Demand Response; Volume IV: Energy Waste Reduction; and Volume V: Primary Data Collection. The Commission issued a memorandum notifying parties that the Potential Studies were filed in the docket and that initial comments were due on October 31, 2025 with reply comments following on November 14, 2025.

Public Hearings

The first public hearing was held on September 9, 2025 (September 9 hearing), in Grand Rapids, Michigan, before Administrative Law Judge Jonathan F. Thoits (ALJ Thoits). Following a brief description of the purpose of the hearing by ALJ Thoits, and statements from the three Commissioners, the Staff presented the contents of an IRP and MIRPP, the various updates and considerations required by Act 231, and the proposed updates to the IRP filing requirements that are subject to the requested public comments. The hearing was then opened to the public and 17 speakers provided comments. Two written comments were also received. The transcript of the hearing was filed in this docket on October 13, 2025.

On October 27, 2025, a second public hearing (October 27 hearing) was held in Auburn Hills, Michigan with Administrative Law Judge James M. Varchetti presiding. The October 27 hearing followed the same format as the September 9 hearing and included verbal comments from 26 interested persons. The Commission also received written comments from 16 individuals. The transcript of the hearing was filed in this docket on November 13, 2025.

Written and Electronic Comments

Along with the notice of the two public hearings, the August 21 order provided an opportunity for interested persons to file written or electronic comments by October 31, 2025, and reply comments by November 14, 2025. Accordingly, in Case No. U-21867, the Commission received written comments from rate-regulated utilities, including Consumers Energy Company (Consumers), DTE Electric Company (DTE Electric) and, Indiana Michigan Power Company (I&M). The Commission also received comments from a wide array of labor, environmental, energy-related, and advocacy groups, including the Michigan Laborers District Council (LiUNA); the Michigan State Conference of the International Brotherhood of Electrical Workers (MSC-IBEW); the Michigan Regional Council of Carpenters and Millwrights (MRCCM); Energy Michigan, Inc (Energy Michigan); the Ecology Center, Environmental Law & Policy Center, the Union of Concerned Scientists and Vote Solar, collectively, the Clean Energy Organizations (CEOs); Abrams Environmental Law Clinic (AELC); Michigan League of Conservation Voters (MLCV); Energy Equity Project; Michigan Biomass, Inc, (Michigan Biomass); and the Michigan Environmental Council, Natural Resources Defense Council, Inc., and Sierra Club (collectively, MNS). The Commission also received comments from Tribal Nations and organizations, including the Keweenaw Bay Indian Lake Superior Band of Chippewa Indians, the Lac Vieux Desert Band of Lake Superior Chippewa Indians (LVD), and the Midwest Tribal Energy Resources Association (MTERA). The Commission received written comments from 99 individuals, while 116 electronic comments were received.

Reply comments were filed by DTE Electric, Consumers, MNS, the Great Lakes Renewable Energy Association (GLREA), and International Transmission Company (ITC).

Comments filed in Case No. U-21570

The Commission also received several comments in the docket of Case No. U-21570, including comments from the Michigan Energy Innovation Business Council (MEIBC), Wolverine Power Supply Cooperative, Inc. (Wolverine), Energy Michigan, I&M, and DTE Electric. The comments filed in Case No. U-21570 have been incorporated into the discussion in Case No. U-21867 and the Commission finds that the docket in Case No. U-21570 should be closed.

The Commission appreciates the incredible number of varied comments filed in this proceeding and is extremely thankful to all utilities, businesses, labor organizations, Tribal Nations, advocacy groups, and other interested persons for contributing their time and insightful perspectives to assist the Commission in advancing Michigan's electrical energy outlook. The Commission carefully reviewed all the written and electronic comments received in Case Nos. U-21867 and U-21570, along with all comments made at the two public hearings, for consideration in finalizing the MIRPP, IRP, the three CEPs, and the Potential Studies, which are discussed pursuant to the applicable sections of the MIRPP, IRP Filing Requirements, the three CEPs, and the Potential Studies.

The next section addresses the substantive changes made to the Staff's recommendations in the MIRPP in light of the comments received, followed by discussions of any changes made to the Staff's recommendations on the IRP filing requirements, the CEPs, and the Potential Studies.

Revised Michigan Integrated Resource Planning Parameters

The Staff's Revised MIRPP consists of required modeling scenarios and sensitivities with each scenario and sensitivity combination established in the planning parameters representing a different vision for Michigan's energy future. The Staff recommended two scenarios.

The Staff's recommended Scenario 1 of the MIRPP largely aligns with Future 3A from Midcontinent Independent System Operators' (MISOs') November 2023 Futures Report. *See* MISO, *MISO Futures 3A: Series 1A Futures* (November 1, 2023). Reflective of MISO's Future 3A, Scenario 1 assumes more aggressive advancement toward electrification and decarbonization. Key components of this scenario are a total energy growth rate of 1.08%, EV adoption reaching 50% of total sales by 2030 but that utilities may develop alternative assumptions, and an 80% carbon reduction by 2042 across MISO. This scenario includes five sensitivities utilities are required to include in the modeling process.

The Staff's recommended Scenario 2 aligns with MISO's November 2023 Futures Report, Future 1a. This Scenario models moderate demand and energy growth, with a 40% reduction in carbon emissions across the MISO region by 2042. The scenario also includes annual energy growth of 0.22%, moderate EV adoption, and continued adoption of electrification. Sensitivities for Scenario 2 include high fuel costs, a 2.17% EWR reduction savings, slower than expected electrification, and variations of large load growth. A more detailed discussion and changes to the Staff's Revised MIRRP provisions follows with a clean version of the MIRPP attached as Exhibit A to this order.

I. Executive Summary

The Commission adopts this section as proposed by the Staff.

II. Background

The Commission adopts this section as proposed by the Staff.

III. Energy Waste Reduction Potential Study

To comply with sections 6t(1)(a) and f(iii) of Act 341, the EWR Potential Study is included in the Potential Studies filed in this docket on October 20, 2025. The Commission adopts the EWR

Potential Study for inclusion in utility plans. In addition, as noted below, the Commission adopts the Staff's proposals relating to EWR, including, for or an electric utility independently administering its own EWR program, modeling that is based upon maintaining a 2.17% EWR savings, and for utilities not already achieving 2.17% EWR savings, ramping the utility's EWR savings to at least 2.17% of prior year sales over the course of three years, using EWR cost supply curves provided in the Michigan state-wide potential study for more aggressive potential. As noted in the Staff's proposals, there should be no artificial cap on EWR savings levels and additional cost effective EWR should be also modeled. There should be no cap on costs associated with EWR programs as long as the program portfolio is cost effective based on a utility cost test score of 1.0 or greater. Finally, the EWR Potential Study may be used to inform technology costs and limits to the total resource amount available for EWR programs and may also be augmented by prior EWR potential studies and/or additional research as well as by the actual experience of EWR programs in Michigan.

IV. Demand Response Potential Study

To comply with sections 6t(1)(b) of Act 341, the DR Potential Study is included in the Potential Studies filed in this docket on October 20, 2025. The Commission adopts the DR Potential Study for inclusion in utility plans. In addition, as noted below, the Commission adopts the Staff's proposals relating to EWR, including that the DR Potential Study may be used to inform technology costs and limits to the total resource amount available for DR programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior potential studies and/or additional research as well as by the actual experience of EWR programs in Michigan.

V. Electrification Potential Study

To comply with sections 6t(1)(j) of Act 341 as amended by Act 231, the Electrification Potential Study included in the Potential Studies filed in this docket on October 20, 2025. The Commission adopts both the Building and Process Electrification Potential Study and the Transportation Electrification Study for inclusion in utility plans. In addition, as noted below, the Commission adopts the electrification assumptions included in the two required Scenarios.

VI. State and Federal Environmental Regulations, Laws and Rules

The Commission adopts this section as proposed by the Staff.

VII. Planning Reserve Margins and Local Clearing Requirements

The Commission adopts this section as proposed by the Staff.

VIII. Modeling Scenarios, Sensitivities and Assumptions

A. Scenario #1

Under the Staff's proposal, Scenario #1 directionally aligns with MISO's November 2023 Futures Report, Future 3a and would be required for utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, and encouraged for multistate utilities.

Consumers recommends the following revision:

> This scenario assumes significant advancements toward electrification that drives a total energy growth rate to 1.08 (or the growth rate specified in MISO's most recent Futures 3a) throughout the Eastern Interconnect. Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030, with a trend toward 100% of vehicle sales continues throughout the remainder of the study period. Using this information, utilities may develop their own demand and energy forecasts ~~for their service territory~~ with description and detail of how their forecast has included the impacts of climate change, electrification, demand side resources, and customer owned distributed generation and how these factors impact overall load and demand.

Consumers' comments, p. 9. Consumers states that it does not have the ability to accurately recreate the specific growth rate for the MISO system and that removing the limiting language "for

their service territory" will allow the company to create a forecast for its service territory and the overarching MISO system that is based on the underlying drivers of growth and capture the intent of Futures 3a. *Id*.

The Commission finds that Consumers' recommendation is reasonable and will allow utilities to model the MISO system, in addition to their own service territory, providing flexibility in modeling a shifting EV sales environment.

DTE Electric suggests the following:

> Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030, with a trend toward 100% of vehicle sales continues throughout the remainder of the study period. **Alternatively, a utility may develop its own high growth assumptions for EV adoption, provided that the assumptions are reasonably supported by reputable source(s) either publicly available or commissioned studies by the utility.**

DTE Electric's comments, p. 4 (emphasis added). DTE Electric suggests the edit to be consistent with the most recent MISO Future 3a. *Id*.

The Commission also finds DTE Electric's recommendation reasonable and will allow flexibility for utilities to adapt to the uncertainty surrounding future EV adoption.

DTE Electric also recommends additional changes for Scenario #1. DTE comments that "a publicly available data source" source should replace the specific reference to the United States Energy Information Administration's (EIA's) most recent Annual Energy Outlook (AEO). As a result, the Commission adopts the following paragraph for inclusion in Scenario #1, with adopted changes in bold.

> This scenario assumes significant advancements toward electrification that drives a total energy growth rate to 1.08 (or the growth rate specified in MISO's most recent Futures 3a) throughout the Eastern Interconnect. Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030, with a trend toward 100% of vehicle sales continues throughout the remainder of the study period **for both the eastern interconnect outside of Michigan and the utility's service territory**. **Alternatively, a utility may develop its own high growth assumptions for EV**

> **adoption, provided that the assumptions are supported by reputable source(s) either publicly available or commissioned studies by the utility whose assumptions and data can be made available for scrutiny.** Using this information, utilities may develop their own demand and energy forecasts for their service territory with description and detail of how their forecast has included the impacts of climate change, electrification demand side resources, and customer-owned distributed generation and how these factors impact overall load and demand.

DTE Electric also recommends striking the following language:

> Electrification growth within the utility service territory and subsequent energy and demand impacts shall be informed by either established proprietary forecasts or publicly available data and account for utility customer trends. Assumed impacts of electrification on energy and demand forecasts shall be clearly delineated and identified in the utility filing. Utility electrification programs should be informed by the Statewide Electrification Study.

DTE Electric's comments., p. 8. DTE Electric further comments that this statement may contradict the Futures 3a EV assumption, as the electrification potential study suggests there may not be a viable path to 50% EVs by 2030, given the present trajectory. *Id*.

DTE Electric also recommends striking both of the following:

> For an electric utility independently administering its own EWR program, load should be modeled based upon maintaining a 2% EWR savings.
>
> The EWR maximum achievable savings opportunity will be established in a potential study by the Michigan state-wide achievable potential with an average life of at least 8 years for EWR measures, at the portfolio level. If the utility is not already at 2.17%, ramp up the utility's EWR savings to at least 2.17% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the Michigan state-wide potential study for more aggressive potential.

Id., pp. 7-8. DTE Electric comments that two points together provide contradictory direction and that a utility should select either 2.0% EWR savings or 2.17% to include in this Scenario. *Id*., p. 9

The Commission appreciates the recommendation from DTE Electric, however adopts the Staff's language for Scenario #1.

MEIBC requests that vehicle to grid (V2G) technologies and applications should be analyzed as a resource in the Filing Requirements as well as in Scenario 1 & 2 of the MIRPP. MEIBC suggests that V2G will become a useful storage asset that will provide benefits to the grid. MEIBC's comments, p. 7.

The Commission appreciates the recommendation from MEIBC and notes that V2G may play a role in the future, however, finds that incentives for adoption are unclear, particularly given that there are currently few commercially available EV models designed to operate bidirectionally. Therefore, the Commission declines to adopt MEIBC's recommendation at this time. This does not prohibit the utility or intervenors from proposing pilot projects to understand the benefits, costs, and performance of V2G in other proceedings.

In regard to modeling energy storage, MEIBC comments that best practices should be more specific and include:

> hourly and sub-hourly optimizations, advanced market dynamics (imperfect and perfect foresight depending on the technology duration, advanced cycling, impact to ancillary market prices), and consideration of multiple value streams (e.g., capacity, ancillary services, deferral of transmission and/or distribution upgrades, operating reserves, peak emissions reductions, etc.).

Id., p. 3.

The Commission notes that energy storage and the wide array of technologies it includes is a developing field. Several resources are included in the MIRPP to provide guidance to utilities about best practices in modeling energy storage. The Commission expects that utilities will utilize these resources as well as new and future information to inform energy storage model development. Although MEIBC raises specific items that could be included, due to the developing nature of the field with a wide array of technology types, and a lack of consensus on how best to integrate best practices into current IRP modeling processes, the Commission finds that being

overly prescriptive could result in limiting what is incorporated into energy storage models. Therefore, the Commission declines to adopt MEIBC's recommendations at this time, but expects the full value of energy storage to be included in utility models, including consideration of all applicable value streams, and the Commission expects to revisit the appropriateness of more prescriptive energy storage requirements in future MIRPP updates.

The Commission also points out that the Study of Long Duration and Multi-Day Energy Storage is included as a reference to provide guidance to utilities as they endeavor to appropriately model energy storage in IRPs. The Study of Long Duration and Multi-Day Energy Storage was the culmination of a multi-year effort to gain information on energy storage, particularly its use and impact in utility planning. This document includes best practices directly applicable to modeling which have been identified in consultation with subject matter experts at the United States Department of Energy's (DOE) National Laboratories. The Commission expects utilities to use this study and new information as it becomes available to model energy storage in IRPs.

B. Scenario #1 Sensitivities

The Commission received several comments on the recommended Sensitivities. In response to Sensitivity 2, which would require the utility to model an unexpected 20% reduction from the utility's base assumption of annual renewable build constraints, the CEOs urge the Commission to include a corresponding sensitivity on the ability to source thermal units with similar constraints to those units. CEOs' comments, pp. 12-13.

The Commission acknowledges that this build constraint sensitivity was created in direct response to procurement issues related to wind and solar at the time of the original MIRPP draft and was meant to analyze potential risks associated with meeting the renewable portfolio standard. The Commission finds that including renewable energy generation procurement from outside of

Michigan to offset any potential build constraints that may occur in state and facilitate a broader selection of wind and solar is reasonable and therefore has updated the sensitivity as follows: "allow the model to supplement the utility's renewable shortfall with out-of-state resources that comply with MCL 460.1028(5)." The Commission also directs the utility to similarly evaluate and discuss any implementation risks that may exist for any out-of-state resources or thermal units selected by the model to replace the constrained renewables accompanied by supporting evidence of such risks.

For Sensitivity 4, which outlines how large load increases should be modeled, MNS emphasizes the need for more robust modeling of large load growth, and that the Commission should require utilities to model three large load growth scenarios—low, medium, and high—and assign probabilities to each scenario to better reflect uncertainty. MNS's comments, p. 16. MNS also urges the Commission to require utilities to disclose information about large load energy profiles and to compare utility forecasts to external sources such as MISO and DOE. *Id*., p. 17.

The CEOs echo these concerns, advocating for greater transparency and accountability in how utilities forecast large loads. The CEOs are concerned that utilities may understate or obscure the impact of data centers on system planning and emissions. CEOs' comments, pp. 9-10. The CEOs emphasize the need for scenario-based modeling and recommends that utilities disclose the status of large load projects, including site control and permitting. *Id*., p. 10.

In reply comments, DTE Electric opposed these proposals, arguing that detailed reporting on large load customers would be commercially sensitive and potentially discriminatory. DTE Electric's reply comments, pp. 2-3. DTE Electric stated the proposed requirements are duplicative, discriminatory, and commercially risky. The company is also concerned that such

requirements could harm economic development efforts and distract from the core purpose of IRPs. *Id*.

The Commission agrees with MNS's recommendation to require utilities to forecast low, medium, and high large load scenarios based upon probabilistic weighting of known interested large loads in addition to the utility's base forecast for each required scenario. This approach provides a more comprehensive framework for understanding the potential impacts of large loads on system planning. Additionally, utilities must show the relationship between this forecast and what the utility has publicly disclosed about load growth from prospective large load customers.[2] The Commission acknowledges that some of the information interested parties seek—such as project-specific details about data centers—is not necessary in order to provide the range of forecasts detailed above and thus declines to adopt this recommendation.

The Commission agrees, in principle, that more information is needed to understand the implications of data center growth and its likelihood of materializing, but finds that other regulatory venues are more appropriate for collecting detailed project specific information and evaluating individual projects. However, to provide information about how the potential for large loads could impact the resources in this scenario the Commission has included the following new sensitivity, "The utility should create a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model."

[2] Publicly disclosed information that should be incorporated into this discussion shall include information from press releases, investor calls, or other forms of public disclosure.

Regarding Sensitivity 5, which would require utilities to model a policy shift to a high investment in off-shore wind starting in the 5th year of the plan and extending to the last year of the plan, I&M comments that Sensitivity 5 lacks clarity, especially on how utilities should approach: (1) reducing build limits for onshore wind and solar to reflect a policy preference for offshore wind, and (2) structuring the modeling inputs or constraints to encourage offshore wind development within the scenario. I&M's comments, p. 2. I&M seeks clarity on how to address these issues.

The CEOs also raise concerns over Sensitivity 5. They note that implementing 50% offshore wind after the 5th year was too aggressive and not realistic. CEOs' comments, p. 13. DTE Electric shares this concern and requests removing the sensitivity entirely, arguing this is not a feasible path to commercialization. DTE Electric's comments, p. 7. The Commission understands the concerns voiced by the CEOs, DTE Electric, and I&M regarding the feasibility of adding large amounts of offshore wind in a relatively short timeframe. The Commission notes that it would be useful to consider other technologies, in addition to offshore wind, for cost effectiveness and feasibility as well. To address these concerns, the utilities will be required to model a sensitivity where the model caps the utility's land-based renewable portfolio at 60% and the remaining resource needs to meet the clean energy plan are achieved through the procurement of other technologies including off-shore wind, out-of-state wind, advanced nuclear reactors, natural gas with carbon capture and sequestration, as well as other resources that the Commission may determine qualify as clean resources pursuant to MCL 460.1003(i). Beyond including offshore wind among the other technologies that could be used to meet the clean energy plan requirements, however, the Commission agrees that the offshore wind development in the Great Lakes is not yet sufficiently mature to require either a specific percentage of resource needs to be met with this

technology or a ramp-up of commercial viability within five years. The Commission expects to revisit this issue in future iterations of these Planning Parameters as the market continues to develop.

MEIBC suggests adding two new Sensitivities in Scenario 1. The first recommendation is to model distributed generation (DG) resources at the maximum limit provided in MCL 460.1173 as well as at 15% and 20% of the utility's five-year average annual peak load. MEIBC's comments, p. 4. Second, MEIBC suggests that utilities "model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization. *Id*., p. 5. Needs should be met within the bounds of required emissions reduction targets."

The Commission finds both recommendations should be adopted. For the first recommendation, the Commission finds value in modeling penetrations of DG resources beyond the minimum levels of DG required to be served under MCL 460.1173, consistent with the direction included in the Filing Requirements to describe how the utility has included DG resources as a selectable resource in its modeling.

For the second recommendation, the Commission finds a sensitivity that models the impact of atypical weather could be potentially beneficial for risk assessment. However, the Commission finds the second element of MEIBC's proposed sensitivity that "[n]eeds should be met within the bounds of required emissions reductions targets" to be unclear. As such, the Commission adopts the following sensitivity for both Scenario 1 and 2: "Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions."

The following are the sensitivities the Commission adopts in Scenario #1:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections (or other publicly available source) by the end of the 20-year study period.

2. Model a renewable resource build constraint consisting of an unexpected 20% reduction from the utility's base assumption. This represents a limited ability to procure or construct renewable resources in the first 6 years of the plan within Michigan. Then allow the model to supplement the utilities renewable shortfall with out of state resources that comply with MCL 460.1028(5), and assess any constraints on replacement resources.

3. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.

4. The utility should create a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model.

5. Model a sensitivity whereby the model caps the utility's land-based renewable portfolio at 60% and the remaining resource needs to meet the clean energy plan are achieved through the procurement of other technologies including but not limited to off-shore wind, out-of-state wind, advanced nuclear reactors, natural gas with carbon capture and sequestration, or other resources that the Commission may determine qualify as clean resources pursuant to MCL 460.1003(i). This sensitivity should include a narrative detailing any implementation risks for the other technology resources.

6. Model the presence of distributed generation resources at the maximum limit provided for in MCL 460.1173 as well as at 15% and 20% of the utility's 5-year average annual peak load.

7. Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions.

C. Scenario #2

Under the Staff's proposal, Scenario #2 directionally aligns with MISO's December 2023 Futures Report, Future 1a and reflects substantial achievement of State and utility

announcements, including generation retirements and environmental goals. This scenario incorporates 100% of utility IRP retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. Scenario #2 assumes an annual energy growth rate of 0.22%, driven by existing economic factors, with moderate EV adoption and customer electrification, resulting in moderate MISO footprint-wide demand and energy growth rates.

Consumers requests the following addition in bold related to Scenario 2 to allow for more flexibility. "For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, Scenario 1 is required, and Scenario 2, including sensitivities, can be replaced with a utility created scenario if assumptions in Scenario 2 have changed such that they are no longer applicable." Consumers' comments, p. 10. The Commission declines to adopt this proposed change. The purpose of having multiple scenarios is to provide meaningful bookends to test assumptions in the planning process. Scenario 1, based on the more aggressive MISO Future 3a, is one bookend, while Scenario 2, based on MISO Future 1a, represents a more modest outlook. While acknowledging the load growth assumptions, in particular, that underlie MISO Future 1a likely represent an overly-conservative view, the Commission still finds value in testing utility plans against this wide set of parameters.

DTE Electric recommends striking, " Fuel cost: Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast," and replacing with, "Fuel cost projections: Increase the natural gas price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections (or other publicly available source) by the end of the 20-year study period." DTE Electric's comments, p. 9. The company comments

that this change aligns the language to be consistent with the similar sensitivity under Scenario 1 to allow the use of other forecasts as the AEO has not been updated since 2023. *Id*., p. 10. The Commission declines to adopt this recommendation as the AEO Low Oil and Gas Supply forecast has been included in the EIA's Annual Energy Outlook 2025.[3]

D. Scenario #2 Sensitivities

The Staff's recommended Scenario #2 Sensitivities are as follows:

> 1. Fuel cost: Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast.
>
> 2. Load projections:
>
> > a. High load growth: For the filing utility's load obligation, increase the energy growth rate by at least a factor of two above the base case energy or 0.5% (whichever is greater, but independent of any load growth from data centers) on a per customer basis. Adjust demand accordingly. For the region included in the scenario utilize load growth that is consistent with the most recent MISO Futures.
> >
> > b. Low load growth: EV adoption and electrification are slower than expected. A utility may develop its own low load growth assumptions for EV adoption, provided that he assumptions are reasonably supported by reputable source(s) either publicly available or commissioned studies by the utility.
>
> 3. If the utility is not already achieving 2.17% EWR, ramp up the utility's EWR savings to at least 2.17% of prior year sales over the course of three years within the utility's Michigan jurisdiction. EWR savings remain at 2.17% throughout the remainder of the study period.

The Commission finds that MNS's comments regarding the potential load growth from data centers is independent of other electrification and is therefore applicable to Scenario #2 in addition to Scenario #1. As such the Commission includes the following new sensitivity for Scenario #2.

> > 4. The utility should create a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base

[3] www.eia.gov/outlooks/aeo/, last accessed December 12, 2025.

load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model.

In addition, as noted above, the Commission also adopts MEIBC's proposed additional weather-related sensitivity as follows:

5. Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions.

IX. Michigan Integrated Resource Plan Modeling Input Assumptions and Sources

The Michigan IRP Modeling Input Assumptions and Sources, Section IX of the MIRPP were updated in the Staff proposal to reflect the changes that the Commission is adopting throughout the MIRPP and the IRP Filing Requirements. These updates include:

1. Updates to the EWR Savings and EWR Costs sections that reflect the updated savings targets pursuant to Public Act 229 of 2023 and the Commission's Energy Waste Reduction Potential Study.

2. Updates to DR Savings and DR Costs sections that reflect the results of the most recent Michigan Demand Response Potential Study.

3. The addition of Storage and related resources to aid in modeling various emerging storage technologies.

4. Updates to Other Resources that include various current best practices in modeling and integrated resource planning.

5. Electrification that reflects the addition of the Michigan's Electrification Potential Study.

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

X. Additional Integrated Resource Plan Requirements and Assumptions

No comments were received on this section of the Staff's proposed MIRPP. The Commission adopts this section as proposed by the Staff.

Integrated Resource Plan Filing Requirements

Attached as Exhibit B to the August 21 order are the Staff's recommendations for the updated IRP filing requirements. The Commission has reviewed the many comments received on Staff's recommendations and appreciates the insightfulness and efforts to assist the Commission in improving the IRP filing requirements process. The discussion below outlines where revisions have been made to the Revised Integrated Resource Plan Filing Requirements. The adopted version of the Revised Integrated Resource Plan Filing Requirements is attached as Exhibit B to this order.

Application Instructions; Schedule; Filing Announcement; Pre-Filing Requests for Proposals

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Schedule

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Filing Announcement

The Staff's proposed filing announcement provisions require information related to the CEP that will be filed with the utility's IRP. No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Pre-Filing Requests for Proposals

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Engagement and Public Outreach Process

Engagement and Public Outreach requirements, formerly referred to as "Stakeholder and Public Outreach", was updated in the Staff's proposal to reflect the inclusion of environmental justice (EJ) communities and Tribal Nations, transparency, and the desired structure of public meetings.

MEIBC recommends that all of the language in this section should be changed to "required" instead of "encouraged." The Commission declines to adopt this recommended change. The adopted language serves to guide the utilities' public engagement and outreach without being overly prescriptive.

MEIBC is supportive of the recommendation for hybrid public meetings for both the general public and specifically for EJ communities. DTE Electric also supports hybrid public meetings but suggests at least one of the public meetings be a virtual meeting, rather than a hybrid meeting. The Commission ultimately finds that the filing requirements should encourage a hybrid structure for the public meetings.

LVD recommends that investor owned utilities (IOUs) in Michigan should establish formal, government-to-government engagement structures with Tribal Nations. LVD's comments, p. 4. The Commission notes that LVD's recommendations were taken into consideration in this section of the filing requirements. In effort to ensure that Tribal Nations are informed of the utility outreach in preparation for filing integrated resource plans, the Commission has added language that directs utilities to provide a direct invitation to all Tribal Nations with Tribal lands in their service territory, thereby ensuring that Tribal Nations are informed and can participate in both the utility's outreach and the contested case process. Importantly, new resources within an IRP are often not location specific, therefore the direct impacts on Tribal lands due to any emission

changes within a three- or six-mile radius may not be known. Additionally, a requirement that utilities designate and identify a single point of contact to receive IRP & CEP related feedback from Tribal Nations has been included. The Commission adopts the Staff's recommendation.

LVD along with MTERA also commented that this case should have been identified as one that may affect the interests of Tribal Nations and that they should have been offered formal consultation on this case. LVD's comments, p. 2; MTERA' s comments, p. 2. The Commission notes that the case is open to all public comment and was not a case type included in the list to be offered formal consultation but has since updated its list so it is included. Nonetheless, the Commission has fully reviewed all comments from the Tribal Nations and Associations, and is committed to ensuring that future updates of the MIRPP and IRP Filing Requirements pursuant to MCL 460.6t will include an offering for formal consultation. In accordance with the statute, these documents will be updated every four years. When the Commission initiates its next update cycle, it will offer consultation accordingly.

Risk Assessment Methodology

Utilities are required to include a thorough risk assessment analysis of the proposed resource plan and the optimal plans for each of the scenarios outlined in the MIRPP. Completing a rigorous risk assessment determines how different resource strategies in the proposed course of action (PCA) and optimal plans would perform under a variety of unexpected potential futures. An integral component of the risk assessment analysis is the inclusion of atypical and extreme weather conditions. Extreme weather events should be included for the past 20 years and are identified by State declarations of emergency.

The Commission received comments regarding the risk assessment section from I&M and Consumers. I&M requests allowing a utility to only perform risk assessment on its PCA rather

than both a PCA and other optimal plans, stating it would allow for a significantly more detailed analysis of the PCA. I&M's comments, p.p. 1-2. Additionally, I&M requests that extreme weather events should not be included in risk assessments as I&M does not keep data on extreme weather events and is unsure how the data would be incorporated. *Id*., p. 2.

In a similar comment, Consumers also suggests removing the inclusion of atypical weather conditions as identified by State declaration of emergency from the risk assessment. Consumers indicated there was a lack of clarity regarding how such events would be included in evaluation from a modeling perspective. Consumers' comments, p. 3.

The Commission declines to adopt the changes suggested by I&M and Consumers. Only providing risk assessment for the PCA would dilute the usefulness of the risk analysis, as there would be no other options for comparison. The Commission notes that atypical weather evaluations have been included in the filing requirements since 2022. The only change that was made in this requirement is to further define extreme weather by the State declaration of emergency criteria. An evaluation of the impact of the PCA's performance during extreme weather aids in understanding how customers may be impacted with resource shifts and changing extreme weather.

Confidential Information

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Definitions

The Staff recommends a new definitions section to aid in ensuring consistency across planning processes. The defined terms are:

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Non-Wires Alternatives - An electric grid investment or project that uses distribution solutions such as DER, energy waste reduction (EWR), demand response (DR), and grid hardware and software and controls, to defer or replace the need for distribution system upgrades.

Environmental Justice Communities – Overburdened, vulnerable, underserved, or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen). If MiEJScreen tool is not available, the utility should work with and take feedback from the Staff, EGLE, and interested parties when determining which other tool or methodology to use.

Environmental Justice Analysis – Identification of and assessment of impacts to Environmental Justice Communities, as well as the identification of communities with a minimum percentile of 75 in either the Low-Income Population or Black, Indigenous, People of Color population layers in the MiEJScreen tool.

Demand-Side Resources - Resources serving resource adequacy needs by reducing or shifting load, which reduces the need for additional generation, including but not limited to EWR, DR, grid and software controls, behind-the-meter distribution connected storage, etc.

Co-Benefits – Benefits that are quantified as part of another planning process that are important for the justification of a resource included in the IRP. Examples include a cost reduction to the distribution system or transmission system that have been evaluated in the distribution planning or transmission planning process.

Several comments were filed on the proposed environmental justice definition. Act 231 requires the Commission to identify Environmental Justice communities (EJ communities) in IRPs. CEOs assert that the only correct interpretation of the statute is one where the Commission creates a list of EJ communities that will be continuously updated. CEOs' comments, p. 1. The Commission finds that this could lead to a delayed inclusion of new data due to timelines related to data collection and subsequent MiEJScreen updates. The Commission also finds that by providing a methodology that clearly identifies what communities are to be included in an EJ analysis, the Commission has indeed determined the EJ communities for the purpose of resource planning.

The Staff's discussions with the Department of Environment, Great Lakes, and Energy (EGLE) and comments from the CEOs resulted in recommendations that the IRP filing requirements include a secondary screen to ensure that disproportionately burdened communities do not slip through the cracks because of a MiEJScreen score that does not qualify for recognition. EGLE agreed with the CEOs' comments resulting in the proposed "Environmental Justice Analysis" definition, which includes an additional identification of "communities with a minimum percentile of 75 in either the Low-Income Population or Black, Indigenous, People of Color population layers in the MiEJScreen tool."

Consumers has concerns that the current definition's inclusion of Black, Indigenous, and People of Color (BIPOC) specifically could create constitutional challenges. Consumers notes that "the overall MiEJScreen score is calculated based on 26 different potential indicators of an EJ community, two of which are Low-Income Population and BIPOC populations. Consumers' comments, p. 6. Consumers comments that it is unclear why, as a matter of policy, the Commission should highlight two of the 26 indicators in its analysis, as opposed to relying on the

tool's scoring system as designed by the EGLE." *Id*. Consumers further recommends triggering an Environmental Justice analysis only if the composite MiEJScreen score is at or above the 80th percentile, as the 75th percentile threshold is not consistent with the recent Commission order in Consumers' last general rate electric rate case. *Id*., p. 7. Consumers defined an EJ community or census tract as one that is above the 80th percentile on the MiEJScreen tool, which was approved by the Commission. *Id*.

MNS disagrees with Consumers' concerns that including an analysis that looks at BIPOC layers would trigger an equal protection clause issue. MNS argues that the 75% BIPOC threshold would not be used to define communities that will or will not receive a benefit, but rather would provide the utilities, the public, and the Commission with information as to how the IRP alternatives impact different communities. MNS's reply comments, p. 2. MNS further argues that the availability of the EJ analysis does not mandate that the Commission take any particular action. Consumers' equal protection clause concern is misplaced and would deprive the public and the Commission of a full understanding of the impacts of the IRP alternatives. *Id*.

EGLE expressed that the way the Environmental Justice Analysis definition suggests using the tool is consistent with proper usage of MiEJScreen and they are supportive of both definitions as written.

The Commission finds a 75th percentile is appropriate for an IRP and declines to adopt Consumers' proposed change to the 80th percentile. The proposed definitions are adopted.

MTERA and LVD comment that Equity and EJ metrics must explicitly identify Tribal lands and communities as EJ communities where applicable, requiring utilities to demonstrate how program benefits and clean energy investments will flow to underserved Tribal areas. The Commission finds it essential to include equity and environmental justice considerations for Tribal

areas to ensure that Tribal lands and voices are not missed due to insufficient public information. Therefore, direct Tribal engagement has been added to the filing requirements in the "Engagement and Public Outreach Process" section.

Approval of Costs

Energy Storage

Although much of this section remains unchanged, the Staff included a provision for energy storage. The energy storage requirements have been added to the IRP filing requirements to facilitate achievement of the statewide energy storage target. The IRP filing requirements require that a utility seek approval of resources necessary to meet a utility's share of the statewide energy storage target no later than December 31, 2029, and include capital costs, operation and maintenance costs, financing costs, procurement strategy, and detail its plans for safe decommissioning, including funds for disposal. In addition, the Energy Storage Target section of the filing requirements, Section IX under the IRP Filing, Data, Documentation heading, requires a utility to describe how it will meet its proportional share of the statewide energy storage target.

The Commission is aware that many public comments addressed concerns over the siting of energy storage facilities. While the Commission acknowledges the importance of siting, it is outside the scope for this proceeding. For the IRP filing Requirements, the Commission finds it necessary to include energy storage requirements and adopts the Staff's language for inclusion in the Revised Filing Requirements.

Labor Standards

Section 6t(8)(c) of Act 231 requires that the construction and maintenance of new or rehabilitated generation capacity resources include the use of registered apprenticeship programs,

payment of prevailing wages, and the use of project labor agreements or collective bargaining agreements.

Labor organizations, including the Michigan Regional Council of Carpenters and Millwrights, LiUNA, and MSC-IBEW, submitted comments urging the Commission to strengthen these requirements. LiLUNA specifically requests that utilities be required to disclose whether they will meet each of the three statutory labor standards individually: (1) use of registered apprenticeship programs, (2) payment of prevailing wages, and (3) use of project labor agreements or collective bargaining agreements. LiLUNA's comments, p. 2. The labor organizations argued that without such specificity, utilities might provide vague or incomplete descriptions that do not demonstrate actual compliance.

The Commission acknowledges the importance of ensuring that labor standards are meaningfully addressed in the IRP process. While the Commission does not adopt the full scope of the labor organizations' recommendations, it agrees that additional clarity is warranted. To address this, a new requirement has been added for supply side, renewable energy, and energy storage resources stating that utilities must provide "a description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6t(8)(c)." This addition ensures that labor standards are explicitly considered during the procurement and cost approval phases, even if not fully detailed in the IRP narrative itself. The Commission expects that the utility will continue to address its progress in ensuring that the labor standards are upheld and include evidence as specific resources are approved, sited, and built to meet the approved IRP.

The Commission affirms the statutory importance of labor standards while recognizing the procedural limitations of the IRP process. By embedding labor standard commitments into the

procurement process, the Commission aims to uphold the legislative intent of Act 231 and promote high-road labor practices in Michigan's energy transition.

Waivers and Process for Smaller and Multistate Utilities

No comments were received on this section. The Commission adopts this section as proposed by the Staff.

Integrated Resource Plan Filing, Data, and Documentation

A utility's IRP filing must demonstrate compliance with MCL 460.6t and must include listed documentation for approval. The Staff's Revised IRP Filing Requirements amended the heading of this section to include data, and added a section requiring, "[a]ny information that the Commission in its orders regarding the utility's previous IRPs or other dockets required to be provided in this present IRP. This information should also be provided to interested persons at public outreach meetings."

No comments were filed on this change. The Commission adopts the change as proposed by the Staff.

Many of the additional subsections under this heading remained the same with no comments filed and therefore, are adopted by the Commission. Those sections that received comments suggesting revisions are discussed below.

Section IV. Analytical Approach

Resource retirements are addressed in this Section, with supplemental requirements in Appendix G of the MIRPP. As currently drafted by the Staff, the retirement analysis in Appendix G is only applicable if a utility presents a retirement study as justification for an early resource retirement or to delay the scheduled retirement of a fossil fuel plant. Appendix G provides a template to evaluate the minimum scenario and sensitivities required for a retirement analysis.

I&M requests clarification for when the Appendix G analysis was required. The Staff reviewed the current language and did not recommend any changes, as it was determined to be sufficiently clear that Appendix G is only necessary if a utility plans an early resource retirement or the delay of a scheduled retirement. The Commission agrees with the Staff's recommendation and therefore, adopts the language proposed by the Staff and finds further clarification unnecessary.

Section VIII. Renewables and Renewable Portfolio Standards Requirements:

Distributed Energy Resources (DERs) are required to be considered as part of the Renewable Portfolio Standards Requirements section of the IRP Filing Requirements. The current draft of the filing requirements requires a utility to describe how it has included distributed generation as a resource in its IRP & CEP modeling.

The CEOs request that utilities clarify which costs for DER are borne by the utility ratepayers compared to DER customers. Additionally, the CEOs suggest requiring utilities to model aggregated DERs as a selectable capacity resource. CEOs' comments, p. 7. The CEOs also comment that utilities should evaluate distributed hybrid blocks that are similar to distributed capacity procurement programs. CEOs' comments, p. 8. By combining this type of program with the aggregated DERs, the CEOs note that it would capture both customer and utility distributed capacity. *Id*., pp. 8-9.

The Commission agrees with the comments to require utilities to model aggregated DERs as a selectable capacity resource and to model the costs of DERs that would be recovered by the utility from ratepayers.

The Commission therefore has added language in Section VIII adopting these recommendations, directing the applicant to:

> [d]escribe how the electric provider has included distributed generation (DG) as a selectable resource within its modeling for both the IRP and CEP, including interconnection to utility distribution as well as behind-the-meter. The utility is required to consider and model aggregated DG, distributed energy resources (DER) and virtual power plants (VPP) as selectable resources in its IRP. The utility should delineate the costs are paid by DG customers to participate in the program and the costs are paid by all rate payers. Only costs to all rate payers should be included when modeling DG resources. Costs paid by the DG customers (program participants) should not be included in the model but should be considered as compared to the applicable bill credit and DG customer savings to analyze expected participation.

The Commission adds that this analysis should not solely identify solar generation existing within the utility's system, but instead utilize the most up-to-date information about trends and costs to predict uptake and create a forecast of future DER resources.

Section XIII also requires utilities to work with the local transmission owner to create an analysis of potential new or upgraded transmission options for the utility.

The CEOs submitted comments requesting the addition of a specific requirement that utilities analyze the inclusion of transmission reconductoring as well as grid enhancing technologies (GETs) as transmission solutions. The CEOs argue that these technologies are usually cheaper and faster to deploy than new or re-built transmission lines, which makes them an effective way to resolve short-term transmission issues.

In response to the CEOs' comments, ITC and DTE Electric both submitted reply comments opposing the suggestions. ITC states that the filing utility would not have the data to complete this analysis. ITC's comments, p. 5. Furthermore, ITC points out that the filing utility would not have the ability to implement GETs. *Id*. DTE Electric suggests that GETs and reconductoring analysis should take place in a transmission planning case and IRP cases should remain focused on long-term planning processes. DTE Electric's reply comments, p. 6.

The Commission finds benefit in analyzing the impact of GETs and their ability to defer or displace transmission and generation resource investment. GETs can provide for lower

transmission constraints and increased market efficiencies; therefore, the Commission finds that GETs should be analyzed and considered as part of the transmission options for the electric utility within the IRP that is required by statute. However, the Commission acknowledges that there is an implementation challenge as the Commission does not have the jurisdiction necessary to require transmission companies to adopt GETs. Nevertheless, including GETs as a transmission option within the IRP may help facilitate GETs consideration within MISO transmission planning processes and development when the benefits and impacts are more fully understood.

Additional reply comments were filed by ITC which raised concerns over Section XIII, (f) and (g). These sections focus on determining interconnection costs, siting locations, and import and export capabilities. ITC suggests that these requirements counter its commitment to open-access and non-discrimination. ITC's reply comments, p. 6. ITC comments that providing this information would not offer value to the long-term transmission analysis in the IRP. *Id*., p. 7. ITC stated it is obligated to engage with utilities regardless of the cost and location factors. *Id*.

The Commission notes ITC has provided this information in past IRP cases, and thus finds it reasonable to continue to require this information in future IRP cases. Additionally, the Commission notes that the current language includes "to the extent available" which allows for flexibility in reporting. Therefore, the Commission declines to adopt ITC's request to remove these sections.

ITC also requests the Commission to update Section XIII, (i) and (j) to include specifications regarding confidential MISO information. ITC comments that it is a MISO member and is subject to MISO's nondisclosure agreement, meaning it cannot disclose the entirety of the information requested in these sections. The Commission acknowledges ITC's concern and amends these sections to allow information to be shared when it is publicly available.

Section XIV – Fuel

This section of the Staff's proposed IRP Filing requirements outlines the information related to fuel required to be provided within the plan. Several comments were received regarding the use of carbon capture and sequestration and hydrogen resources within utility IRPs.

The Commission notes that natural gas facilities with carbon capture and sequestration are included in the definition of a clean energy system (CES) as part of Act 235 so long as the facility uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. MCL 460.1004(i)(ii).

The Commission also notes that hydrogen is not included in the definition of a CES under Act 235 and to date, the Commission has not promulgated rules to further define other resources that qualify as a CES pursuant to MCL 460.1003(i)(iv). Therefore, the Commission declines to determine what type of hydrogen technologies can be included as a CES at this time. However, this does not prohibit a utility from investigating hydrogen as a possible future resource.

With regard to the IRP filing requirements, the Staff's proposal was modified to include Section XIV (k) whereby the utility shall include new generation or retrofitted generation costs to connect to fuel and store CO_2 when applicable. Similarly, the MIRPP has been updated to include the U.S. EIA's AEO price reference for fossil generation that uses carbon capture and storage (CCS).

MNS recommends that guidance should be provided to utilities specifying which costs should be included in IRP modeling. MNS comments that hydrogen costs and carbon capture and sequestration technology costs should be modeled using the high-end of industry projections for costs and include any construction or operational costs projected by the utility to operate the hydrogen generation technology or the carbon capture technology, pipeline or other transportation

costs, monitoring, and sequestration costs, and/or any contracted costs to use technology and infrastructure owned and operated by a third party. MNS's comments, pp. 7-8. MNS suggests cost estimates should also account for the cost of energy to power the hydrogen or carbon capture technology. *Id*., p. 8.

DTE Electric filed reply comments opposing the use of the high-end costs for carbon capture. DTE Electric notes that MNS's recommendations introduce a bias because no other resource is expected to use the high-end industry costs regardless of technology maturity or known market volatility and that MNS has not provided justification for such a requirement.

The Commission is not persuaded that there is sufficient justification to require high-end costs for only carbon capture at this time and therefore declines to adopt MNS's recommendations on the matter. The Commission reiterates that a utility is expected to support the cost estimates used within its IRP model for all resources with evidence, CCS included.

MNS further comments that utilities should be expected to provide evidence that includes laboratory and/or in-field data as well as site specific data demonstrating that the proposed CCS project will meet the clean energy standard and will have the ability to permanently store carbon dioxide.

The Commission agrees that this information is important. If a utility is proposing to include a natural gas generation facility that includes carbon capture and storage as a CES, the utility shall provide sufficient evidence to demonstrate that the facility meets the requirements of MCL 460.1003(i)(ii).

Section XVII – Proposed Resource Plan

This section of the Staff's proposed IRP Filing Requirements outlines information to be provided about the utility's proposed resource plan. Michigan Biomass provided comments about

biomass as a resource, highlighting the fact that it is reliable, renewable and dispatchable power that brings diversity to the state's energy portfolio and resilience and flexibility to the grid. They encourage the Commission to continue to explore ways to fully value biomass power services in the IRP process including potential frameworks to identify the services that biomass energy provides.

In response to these comments, the Commission notes the need for generation diversity in section XVII subsection (e) of the IRP Filing Requirements. As the Commission noted in the 2019 Statewide Energy Assessment, "[a] framework to capture the value of diversity in generation resources should also consider the value provided by Michigan biomass facilities . . . ." Michigan Statewide Energy Assessment Final Report, Sept. 11, 2019, filed in Case No. U-20464, p. 187, n. 203. In addition, the Commission has previously highlighted the need for coordination with Regional Transmission Organizations (RTOs) around the development of wholesale market products that "send appropriate price signals to support the attributes that contribute to operational flexibility." April 25, 2024 order in Case No. U-21568, p. 20. While the Commission continues to press for the development of ancillary services markets within RTOs, the current absence of such markets make it all the more important to try and quantify the energy and other values that dispatchable renewable resources like biomass facilities can provide. As such, the Commission has revised the language of the Staff's proposed Filing Requirements to include a detailed description of "[t]he impact of the CEP on the diversity of the utility resource portfolio. Include qualitative and quantitative details that include consideration of the benefit associated with resources that add to generation diversity and provide a specific and monetarily quantifiable benefit that would not be achievable absent the resource."

Section XX -Rate Impact, Financial Information, and Affordability

In this Section, the Staff proposal outlines requirements for utilities to compare the affordability impact of the PCA to the previously approved build plan. Utilities must describe the methodology and data sources used in its analysis, identify income ranges where the energy burden is projected to be at or above 6%, and discuss available assistance programs, EWR, or other measures that could mitigate increased energy burdens. Along with this requirement, the Commission has added Appendix 2 as a non-binding example methodology that includes calculating projected rate and bill impacts, estimating average annual energy costs, creating an income distribution for the utility's service territory, adding PCA impacts to household energy costs, and calculating energy burden by income range. The Commission notes that this approach provides a balanced framework that ensures affordability is addressed without imposing overly prescriptive or administratively burdensome requirements.

The CEOs support the 6% energy burden threshold but urge the Commission to go further, commenting that each utility should be required to complete a more detailed analysis which includes: (1) the total number of energy burdened households, and (2) the average energy burden of its residential customer base overall and subdivided by census block. CEOs' comments, p. 3. The CEOs also recommend calculating an "affordability gap" and requiring utilities to explain how their PCA would reduce the gap over time. *Id*., pp. 3-4. The CEOs urge the Commission to require the Appendix 2 methodology instead of leaving it as optional. *Id*., p. 4.

MNS agrees with the inclusion of affordability requirements but proposes two key changes. First, if any income group exceeds the 6% burden, the utility should be required to either propose mitigation measures or explain why it is not doing so. MNS's comments, p. 3. Second, MNS asserts the example methodology in Appendix 2 should be standardized across utilities to ensure

consistency and comparability. *Id*. MNS emphasizes that affordability must be actively addressed, not just analyzed. *Id*.

AELC strongly supports the inclusion of affordability and the 6% threshold. They urge the Commission to also require analysis of racial disparities in affordability, and comments that without this analysis, long-term planning and resource allocation may disparately affect BIPOC communities. AELC's comments, p. 2. AELC emphasizes that affordability must be addressed now, not just in future planning. *Id*.

Consumers acknowledges the challenge of energy burdens greater than 6% and supports targeted outreach using mapping tools such as MiEJScreen rather than household-level data. Consumers suggests collaboration with the State of Michigan to improve outreach and comments that focusing outreach via a heat-map-like approach is more likely to result in a cost-effective balance of administrative effort and collaboration. Consumers' reply comments, p. 3.

DTE Electric opposes the CEOs' proposal to calculate affordability gaps and census-block level burdens and argues that these are outside the scope of the IRP statute, overly burdensome, and not relevant to determining the reasonableness of the PCA. DTE Electric contends that such analysis would involve highly subjective assumptions and could distract from the core purpose of IRPs. DTE Electric's reply comments, p. 5.

The Commission acknowledges the thoughtful and well-supported recommendations from interested parties, particularly the calls for deeper analysis of affordability gaps, racial disparities, and standardized methodologies. These concerns are valid and reflect the growing need to ensure that energy planning does not exacerbate existing inequities. However, the Commission believes that requiring utilities to propose mitigation programs or to calculate affordability gaps within the IRP process could introduce complexity and subjectivity that may not improve the quality of

resource planning. The Commission finds that inclusion of a 6% energy burden threshold, a requirement to compare the PCA to the previous build plan, and a discussion of mitigation options provide a clear and actionable framework for utilities to assess affordability impacts within resource planning. Broader analysis of the affordability gap may be more appropriate for a rate case where cost allocation, cost recovery, and rates are all determined.

The Commission encourages utilities to use the Appendix 2 methodology as a guide and to provide transparent, meaningful analysis of affordability impacts. At the same time, the Commission remains open to exploring these issues further in other regulatory contexts, such as rate cases, EWR plans, or other affordability-focused dockets, where more granular data and mitigation strategies may be more appropriately addressed.

Section XXIII: EGLE Advisory Opinion

The Staff notes that EGLE assisted with the development of this section within the Staff's proposal. This section includes total emissions data on a facility/unit level, air impact analysis through the use of Benefits Mapping and Analysis Program (BenMAP) or the Co-Benefits Risk Assessment (COBRA), an EJ analysis for units within 3 miles of EJ communities, and qualitative assessments of the PCA's reduction to the health and safety of individuals in EJ communities.

The CEOs submitted comments that requested the use of BenMAP or COBRA and an additional tool called Intervention Model for Air Pollution (InMAP) in EGLE's air emissions impact analysis. The CEOs argue that InMAP is a peer reviewed, air quality model that runs at a higher resolution where there is high population density and that a combination of the two models – COBRA or BenMAP and inMAP – will provide a more complete picture of the health impacts of PCAs and generation resources.

DTE Electric, Consumers, and EGLE all contend that InMAP's newer, less validated model is not necessary and does not provide much, if any, improvement in EGLE's health impact analysis. DTE Electric and Consumers comment that InMAP is an open-source model, which DTE Electric argues calls into question the validity of its results.[4]

The Commission supports the use of open and transparent tools. At this time, the Commission agrees with EGLE that the use of BenMAP or COBRA is sufficient and declines to also require the use of InMAP.

Also responding to the proposed EGLE Advisory Opinion section, Consumers and DTE Electric submitted reply comments that take issue with the six-mile radius for PM 2.5 and NOx emissions analysis, suggesting instead that a three-mile radius would be more appropriate for consistency's sake, as it matches the three-mile radius of units for EJ analysis.

The Commission is not persuaded that a three-mile radius for consistency's sake is warranted and therefore disagrees with Consumers and DTE Electric and adopts that the language proposed by EGLE and the Staff requiring a six-mile radius.

Within the EGLE Advisory Opinion section, Section XXIII(a) Scope of portfolio build plans, Portfolio 1 is defined as, "the previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period)," as it is necessary to have a point of comparison.

Consumers and MNS both disagree in comments with Portfolio 1's usage due to several factors, including the updated Michigan energy laws, significant load additions to the new IRP that were not included in the previous IRP, and new cost-related assumptions data for this IRP.

[4] The Commission notes that BenMAP is also an open-source model.

The Commission, in consultation with EGLE, acknowledges these concerns and understands that the assumptions utilized in the previous IRP no longer reflect the reality of today, however, the Commission agrees with the Staff that comparison to the previously approved PCA could provide useful information, therefore adopts the Staff's proposed language and maintains the requirement for Portfolio 1 as drafted in the Staff proposal.

The Filing Requirements also provide that an "assessment should evaluate whether the utility's proposed PCA reduces harm to the health and safety of individuals in Environmental Justice Analysis communities," and the "changes in health, safety, and welfare of individuals in environmental justice communities from the PCA."

MNS supports this language. Consumers and DTE Electric take issue with including "safety" in the discussion. They do not believe that safety should be considered in an EJ analysis because emissions and other environmental externalities do not result in safety-related impacts.

The Commission, with advice from EGLE, disagrees with the utilities as the following language came directly from the statute, "[w]hether the plan in comparison to any prudent and feasible alternatives adequately reduces harms to the health, safety, and welfare of individuals in environmental justice communities." Therefore, the Commission adopts the Staff's proposed language.

Clean Energy Plans

Attached to the August 21 order are the three CEP filing requirements documents proposed by the Staff: (1) draft CEP filing requirements for rate-regulated electric utilities, (2) draft CEP filing requirements for Michigan municipalities, and (3) draft CEP filing requirements for Michigan electric cooperatives and alternative electric suppliers (AESs). The CEP filing requirements were included in the notice for the two public hearings along with the solicitation for written and

electronic comments. The following combines the three CEP filings into one discussion with the final "Clean Energy Plan Filing Requirements for Rate-Regulated Electric Utilities", "Clean Energy Plan Filing Requirements for Michigan Municipalities, and "Clean Energy Plan Filing Requirements for Michigan Electric Cooperatives and Alternative Electric Suppliers" attached to this order as Exhibits C, D, and E, respectively.

Engagement and Public Outreach

Public outreach requirements for CEPs are outlined in Section 51 of Act 235. While each type of utility has different requirements for engagement, the Commission encourages all utilities to promote engagement early in the CEP process. Rate-regulated utilities should engage participants about the IRP and CEP development simultaneously. Cooperatives and AESs are encouraged to discuss the engagement process in their CEP filings. As a part of the engagement process, Cooperatives and AESs are encouraged to create a webpage to allow community members to submit feedback in the four to six months prior to the CEP filing. Municipalities are not required to complete additional engagement processes, as they are governed by the municipality itself.

Wolverine submitted comments regarding the public outreach section of the CEP draft for Cooperatives and AESs. Wolverine recommends removing the pre-filing comment opportunity as well as removing the suggestion to create a webpage, stating that they are not required under Section 51. Wolverine's comments, p. 3.

The Commission notes that the current language in the CEP draft highlights that the decision to host a webpage is not an explicit requirement but is encouraged. The Commission, therefore, declines the suggestion from Wolverine and retains the Staff's recommended section on engagement for cooperatives and AESs. The Commission also encourages public engagement and therefore declines to adopt the recommendation to remove the pre-filing comment opportunity.

Comments were also received from MTERA. MTERA requests the implementation of explicit requirements for a utility to consult with Tribal Governments within its service territory as part of its CEP and IRP engagement. MTERA's comments, p. 3. Tribal engagement has been added to the IRP Filing Requirements as previously discussed. Given that rate-regulated utilities will file CEPs with IRPs and are expected to conduct engagement simultaneously, the Commission finds no need for duplicative language in the CEP.

Confidential Information

Energy Michigan requests additional specifications for filing confidential information. Energy Michigan's comments, p. 3. The Staff did not recommend a change to the language in the Staff proposal as contracts are not explicitly required to be filed with the CEP. Utilities are expected to file a description of how the resource transition will take place, key milestones for construction, and implementation of the plan. Additionally, confidential information is protected through non-disclosure agreements that are signed by parties in IRP cases, and therefore, extend to CEPs filed along with the IRP. The Commission declines to adopt Energy Michigan's request to add additional specifications for filing confidential information at this time, however, the Commission notes it is open to future proposals to ensure that the confidentiality of sensitive information is maintained.

Clean Energy Compliance

Act 235 defines a clean energy portfolio as the percentage of an electric provider's total retail electric sales consisting of clean or renewable energy. Consumers recommends that rate-regulated utilities be allowed the option to use up to six months of clean energy generation from both the prior year and the subsequent year to meet the clean energy portfolio requirement for the

compliance year. Consumers' comments, p. 10. Consumers voices concerns regarding the inability to bank clean energy credits similar to renewable energy credits (RECs) as well as the unpredictability of the MISO market dispatch for clean generation. *Id*. Consumers argues that allowing utilities to use past and future clean generation would be similar to the flexibility allowed in REC portfolio attainment. *Id*., pp. 11-12.

The Commission finds that the use of clean energy that has not yet been generated is not a reasonable option. However, the Commission clarifies that one renewable energy credit retired for RPS compliance is counted in the Clean Energy Plan Template toward Clean Energy Compliance. In addition, the Commission finds that a utility can retire one banked REC for one megawatt-hour (MWh) of clean energy in the year for which the utility is complying with the standard because, by definition in MCL 460.1003, a Clean Energy Portfolio "means the percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy. The Commission finds that this approach provides the necessary flexibility in the years where MISO does not dispatch clean generation resources as often as expected or there are other unexpected changes in resource run time that need to be accounted for. Therefore, the Commission finds Consumers' recommendations unnecessary.

Accounting of Voluntary Green Pricing and Renewable Energy Credits

In the CEP filings, all rate-regulated utilities are required to complete a CEP template which includes total electric sales, clean energy standard requirements, and the total clean energy percentage achieved annually. The template, attached as Appendix A to the draft CEP filing requirements for utilities, spans a 20-year study period, beginning in 2026.

Consumers suggests several edits to the template to clarify the role of RECs and voluntary green pricing (VGP) in clean energy portfolio. First, Consumers suggests including the clean

energy percentage achieved annually in years 2026-2034 in the template, even though there is not currently a clean energy portfolio requirement prior to 2035. Consumers' comments, p. 10. Additionally, Consumers requests to identify VGP MWh in a separate line in the template. Originally, the Staff's draft assumed that VGP was included in the "Company Owned Renewable Energy" and "Renewable Energy Power Purchase Agreements" lines. *Id*. Lastly, Consumers suggests the addition of two new template lines that would clarify REC accounting. These lines are intended to demonstrate all purchased RECs as well as RECs reported pursuant to MCL 460.1029(4).

The Commission agrees with Consumers' comments regarding the CEP template changes, including VGP as its own energy type as well as the additional REC accounting lines. The Commission finds these changes make the template more aligned with the current REP reporting requirements, and therefore Appendix A has been modified accordingly.

Reporting

The Commission finds that regular reporting of progress towards compliance to be important. As such, the Commission directs rate-regulated utilities to complete an annual report outlining compliance with CEP requirements. This report is to be filed each year alongside the utility's IRP annual report and filed in the IRP docket. It shall provide the actual year-over-year CEP attainment. This report should simply be a resubmission of the CEP template updated with actual MWh values for both retail sales and corresponding generation for all years where actual amounts are available. Additionally, all non-attainment should also be included and thoroughly described in the report.

The Commission adopts the three CEP filing requirements as recommended by the Staff with the modifications discussed in this order.

Subsequent Integrated Resource Plan Amendments

The Commission recognizes that there is an unprecedented level of uncertainty about the future of utility load, demand, and regional resource adequacy constructs. By design, a utility is expected to revise its plan at least every five years. The Commission finds that filing revised IRPs every five years works well in times when there are only small annual changes impacting resource adequacy; however, that is not what is being experienced today. Given the number of changes taking place with respect to resource adequacy constructs, large load additions, and the continued federal policy changes, the Commission finds, in some situations, five years will be too long between IRP filings to ensure that utilities are prudently planning to meet the needs of their customers. Therefore, the Commission directs rate-regulated utilities to file amended IRPs to consider the impacts of projected changes in load or demand that exceed a 10% increase or decrease as soon as practicable when considering new load additions. The Commission finds that the utility could file a focused IRP amendment to address unexpected load or demand changes within its five-year cycle so long as a full IRP that revisits the entire planning model is completed every five years. Any focused plan amendment shall also account for any updates in the MIRPP or IRP Filing Requirements that may have changed from the previously approved IRP. Additionally, the Commission directs utilities to evaluate MISO's Direct Loss of Load (DLOL) resource adequacy construct and its impacts, once finalized, on the resource adequacy of the utility's most recently approved plans. Should a utility find that the addition of a new large load, the implementation of revised resource adequacy provisions at the RTO, or any other significant change causes a need for additional capacity resources in the next five years, the utility should work diligently to file a new IRP or an IRP amendment as soon as practicable.

Conclusion

Revising the MIRPP and the IRP Filing requirements is a major undertaking that has been conducted over several years. The Commission appreciates the work from the Staff, the utilities, advocacy groups, Tribal Nations and other persons interested in moving Michigan's energy future forward. The Commission appreciates the efforts of the collaborative to ensure that the process is transparent and strives to provide energy equitably across the State. The Staff's proposed MIRPP, the IRP Filing Requirements, the three CEP Filing Requirements, and the Potential Studies are adopted, as modified within this order.

THEREFORE, IT IS ORDERED that:

A. The Michigan Integrated Resource Planning Parameters, attached to this order as Exhibit A, complies with the mandates set forth in MCL 460.6t(1) and (2) and is approved by the Commission.

B. The Michigan Integrated Resource Plan Filing Requirements, attached to this order as Exhibit B, complies with the mandates set forth in MCL 460.6t(1) and (2) and is approved by the Commission.

C. The Clean Energy Plan Filing Requirements for Rate Regulated Utilities, attached to this order as Exhibit C, is approved by the Commission.

D. The Clean Energy Plan Filing Requirements for Michigan Municipalities, attached to this order as Exhibit D, is approved by the Commission.

E. The Clean Energy Plan Filing Requirements for Michigan Electric Cooperatives and Alternative Electric Suppliers, attached as Exhibit E, is approved by the Commission.

F. The Clean Energy Plan Template, attached as Exhibit F to this order, is approved by the Commission.

G. Each electric utility whose rates are regulated by the Commission shall demonstrate compliance with the Michigan Integrated Resources Planning Requirements, the Integrated Resource Plan Filing Requirements, and the Clean Energy Plan Filing Requirements for Rate-Regulated Utilities, as set forth in this order.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at LARA-MPSC-Edockets@michigan.gov and to the Michigan Department of Attorney General - Public Service Division at sheac1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Daniel C. Scripps, Chair

Katherine L. Peretick, Commissioner

Shaquila Myers, Commissioner

By its action of December 18, 2025.

Lisa Felice, Executive Secretary

MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

U-21570 & U-21867

Pursuant to Public Act 341 of 2016, as Amended by Public Act 231 of 2023, Section 6t

December 18, 2025

Table of Contents

I. Executive Summary

This Michigan Integrated Resource Planning Parameters (MIRPP) document was developed as a part of the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes one required and one optional integrated resource plan (IRP) modeling scenarios, each with multiple sensitivities per scenario, for the rate-regulated utilities in Michigan's Upper and Lower Peninsulas to use when conducting integrated resource plans. The scenarios and sensitivities are designed to test varying resource portfolios. The scenarios, sensitivities, and modeling parameters are more aptly characterized as stressors utilized to test how different future resource plans perform relative to each other with respect to affordability, reliability, adaptability, and environmental stewardship. In some instances, scenarios and sensitivities intentionally push the boundaries on what may beviewed as probable and could be considered as bookends on the range of possible future outcomes. Utilities may also include separate additional scenarios and sensitivities in IRPs and may use different assumptions or forecasts for the additional scenarios and sensitivities. However, the assumptions and parameters outlined in the required scenario should be used. Including the scenarios will ensure that Michigan's electric utilities consider a wide variety of resources such as renewable energy, demand response (DR), energy waste reduction (EWR), storage, distributed generation technologies, voltage support solutions,and transmission and non-transmission alternatives, in addition to traditional, clean energy system, and fossil-fueled generation alternatives for the future. This IRP parameters document also contains numerous modeling assumptions and requirements, specifies sensitivities for each scenario, identifies significant environmental regulations and laws that affect electric utilities in the state, and identifies required planning reserve margins and local clearing requirements (LCRs) in areas of the state.

The DR, EWR, and Electrification Potential Studies were completed in August of 2025. Each of these studies have an influence on integrated resource

planning and are incorporated into the Commission's December 18, 2025, order in Case No. U-21867 for the 4-year update, pursuant to PA 341 Section 6t as amended by Public Act 231.

Section 6t (1) requires that the IRP parameters, required modeling scenarios and sensitivities, applicable reliability requirements, applicable environmental rules and regulations, and the DR and EWR potential studies be re-examined every five years.

II. Background

On November 29, 2023, Public Act 231 was signed into law. The law requires that the Commission shall commence a proceeding by August 31, 2025, that ultimately provides the rate regulated utilities with information needed to conduct IRPs. The Commission issued an order in U-21570, directing Staff to file a redline version of the Michigan Integrated Resource Planning Parameters and to engage with interested persons to seek comment on the amendments in preparation for the August 31, 2025, deadline.

III. Energy Waste Reduction Potential Study

To comply with PA 341 Section 6t (1) (a) and (f) (iii).

IV. Demand Response Potential Study

To comply with PA 341 Section 6t (1) (b).

V. Electrification Potential Study

To comply with PA 341 Section 6t (1) (j) as amended by PA 231.

VI. State and Federal Environmental Regulations, Laws and Rules

Appendix E contains a regulatory timeline of the environmental regulations, laws and rules discussed in this section.

Section 460.6t (1) (c)

To comply with PA 341 Section 6t (1) (c)

Federal rules and laws:

Clean Air Act – The Clean Air Act (CAA) is a United States federal law designed to control air pollution on a national level. The CAA is a comprehensive law that established the National Ambient Air Quality Standards (NAAQS), Maximum Achievable Control Technology Standards (MACT), Hazardous Air Pollutant Standards, and numerous other regulations to address pollution from stationary and mobile sources.

National Ambient Air Quality Standards – Title 1 of the CAA requires the United States Environmental Protection Agency (USEPA) to set NAAQS for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public. NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standards are set at a level that is protective of human health with an adequate margin of safety. Secondary standards are protective of public welfare, including protection from damage to crops, forests, buildings, or the impairment of visibility. The adequacy of each standard is to be reviewed every five years. The six criteria pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide (SO_2).[1]

[1] The most recent NAAQS can be accessed here: https://www.epa.gov/criteria-air-pollutants/naaqs-table.

In February 2024, the USEPA strengthened the primary health-based annual PM2.5 NAAQS to 9 micrograms per cubic meter. The previous primary health-based annual PM2.5 standard was 12 micrograms per cubic meter, which was last updated in 2012. The primary and secondary welfare-based PM2.5 standards, secondary annual health-based PM2.5 standard and the primary and secondary PM10 standards were retained and therefore remain unchanged. EGLE reviewed PM2.5 data and provided its attainment status recommendations of the areas not meeting the new standard to USEPA in February 2025. EGLE recommended (based on monitoring and source emissions data, meteorology and geography) that Kalamazoo and Wayne Counties be designated nonattainment for the new PM2.5 standard. USEPA has one year to review data and make its own determinations of attainment/nonattainment.

On March 25, 2025, USEPA announced that it would reconsider the Biden Administration's rule tightening the PM2.5 standard. The action is being taken as one of USEPA's 31 deregulatory actions intended to advance the Trump administration's day one executive orders. USEPA's attempt to revise the Biden Administration's PM2.5 standard will be subject to a formal rulemaking process with public notice and comment periods. In addition to this reconsideration, USEPA has indicated that it will release guidance to increase the flexibility on implementation of the NAAQS, reforms to new source review and new direction on permitting obligations. USEPA has not yet published a formal proposal to reconsider the PM2.5 NAAQS and the exact timeframe to do so is not currently known.

Nonattainment areas are regions that fail to meet the NAAQS. Locations where air pollution levels are found to contribute significantly to violations or maintenance impairment in another area may also be designated nonattainment. These target areas are expected to make continuous progress in controlling emissions within their boundaries. Those that do notabide by the

CAA requirements to reign in the emissions of the pollutants are subject to USEPA sanctions, either through the loss of federal subsidies or by the imposition of controls through preemption of local or state law. States are tasked with developing strategic plans to achieve attainment, adopting legal authority to accomplish the reductions, submitting the plans to the USEPA for approval into the State Implementation Plan (SIP), and ensuring attainment occurs by the statutory deadline. States may also submit a plan to maintain the NAAQS into the future along with contingency measures that will be implemented to promptly correct any future violation of the NAAQS.

Sulfur Dioxide Nonattainment Areas – In 2010, the USEPA strengthened the primary NAAQS for SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

Following the partial disapproval of EGLE's attainment SIP, and due to a lawsuit related to a portion of the SIP, USEPA pursued development of a Federal Implementation Plan (FIP) for the nonattainment area. In January 2022, USEPA made the formal determination that southern Wayne County did not attain the SO_2 NAAQS by the 2018 deadline.

USEPA completed the FIP and a public comment period was held during June and July 2022. USEPA finalized the FIP effective in November 2022. The FIP proposed emissions limits and associated requirements for several area sources, including U.S. Steel (Ecorse and Zug Island), EES Coke, Cleveland-Cliffs Steel Corporation (formerly AK or Severstal Steel), and Dearborn Industrial Generation (DIG). In addition, USEPA proposed to include the Carmeuse Lime emission limits, specified in Permit to Install 193-14A, and the DTE Energy (DTE) Trenton Channel emission limits, specified in Permit to Install 125-11C, which had already been incorporated into Michigan's SIP. The FIP included an attainment demonstration and served to supplement USEPA's prior action, which concluded that Michigan satisfied the emissions inventory and new source review requirements for the area.

In December 2023, EGLE submitted its SIP revision to supplement the attainment demonstration that USEPA conditionally approved on March 23, 2023. An amendment/supplement to this SIP revision was submitted to USEPA in April 2024 to correct an omission in the original submittal.

Once all of the elements of the SIP had been implemented, EGLE worked to complete a redesignation request for southern Wayne County which was submitted for review and approval to USEPA in May 2025. The USEPA has 18-months to approve or deny EGLE's redesignation request.

On September 26, 2024, USEPA proposed to determine that the St. Clair SO2 nonattainment area attained the 1-hour primary SO2 NAAQS by the September 12, 2021, attainment date.

In early 2025, USEPA requested that EGLE provide additional information to supplement the previously submitted redesignation request for St. Clair County. EGLE is in the process of finalizing the supplemental submittal and will submit it to USEPA for approval once complete.

Round three designations were to address all remaining undesignated areas by December 31, 2017. The USEPA sent a letter to Governor Snyder on August 22, 2017, 120 days prior to the intended designation date, indicating that Alpena County and Delta County are to be designated as unclassifiable/attainment areas. Remaining areas of Michigan that were not required to be characterized and for which the USEPA does not have information suggesting that the area may not be meeting the NAAQS or contributing to air quality violations in a nearby area that does not meet the NAAQS, were also designated as unclassifiable/attainment.

Ozone Nonattainment Areas: In 2015, the USEPA strengthened the primary NAAQS for ozone, establishing a new 8-hour standard of 70 ppb.

On August 3, 2018, Michigan was designated marginal nonattainment for the 2015 ozone NAAQS in four areas (ten counties) of the state. In southeast

Michigan, the seven-county area encompassing Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne counties and on the west-side, two partial counties including Allegan and Muskegon and one full county, Berrien were found to have design values[2] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021.

On May 19, 2023, USEPA determined based on "complete, quality-assured, and certified ambient air monitoring data for the 2020-2022 design period" that southeast Michigan achieved attainment of the 2015 ozone NAAQS. This determination was based on the exclusion of certain exceedances that were determined to be due to exceptional events, namely Canadian wildfire smoke. As a result of the CDD, based on the exclusion of the exceptional event-influenced data, USEPA suspended the requirements for the area related to attainment of the 2015 ozone NAAQS for as long as the area continues to attain.

On December 17, 2024, USEPA published a final determination notice indicating that the western Michigan counties failed to attain the 2015 ozone NAAQS by the applicable attainment deadline. On January 16, 2025, the west Michigan counties were officially reclassified from moderate to serious ozone nonattainment by USEPA. EGLE is currently working to complete the required SIP submittals for these areas.

Cross-State Air Pollution Rule – The Cross-State Air Pollution Rule (CSAPR) was promulgated to address air pollution from upwind states that is transported across state lines and impacts the ability of downwind states to attain air quality standards. The rule was developed in response to the Good Neighbor obligations under the CAA for the ozone standards and fine particulate matter standards. CSAPR is a cap-and-trade rule which regulates the emission of SO_2

[2] The design value is the three-year average of the 4th highest 8-hour ozone value).

and NO_x from fossil-fueled electric generating units (EGUs) through an allowance- based program. Under this program, NO_x is regulated on both an annual basis and during the ozone season (March through October). Each allowance (annual or ozone season) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. The state currently has Good Neighbor obligations for the 2015 ozone standard.

On March 12, 2025, UESPA announced plans to roll back the Good Neighbor Plan. The Supreme Court, in an opinion released in June 2025 stated that States could contest USEPA's earlier decision to first disapprove state good neighbor plans in regional appellate courts instead of the United States Court of Appeals for the District of Columbia Circuit which is where such challenges are usually heard. USEPA is currently reviewing the Court's opinion.

Mercury and Air Toxics Standards – Section 302 of the CAA requires the USEPA to adopt MACT for hazardous air pollutants (HAPs). The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires new and existing oil- and coal-fueled facilities to achieve emission standards for mercury, acid gases, certain metals, and organic constituents.

On May 7, 2024, USEPA finalized updates to the MATS rule that were first proposed in April 2023. The updated rule strengthens the national emission standards for hazardous air pollutants (NESHAP) based on an evaluation of the residual risk and technology review. The final rule further limits the emissions of non-mercury HAPs by reducing the existing emission standard for filterable particulate matter by two-thirds as well as strengthens monitoring and compliance requirements for coal- and oil-fired EGUs by requiring the use of continuous emission monitoring systems. Start-up requirements were also revised to allow for better emissions performance during startup activities.

On June 11, 2025, USEPA proposed to repeal certain amendments of the MATS rule finalized in 2024. With this action, USEPA is proposing to repeal the

filterable particulate matter (fPM) standard for existing coal-fired EGUs of 0.010 pounds per million British thermal units (lb/MMBtu) of heat input (previous fPM standard of 0.030 lb/MMBtu would remain in place), and the fPM emission standard compliance demonstration requiring all coal- and oil-fired EGUs to use PM continuous emission monitoring systems (CEMS). In addition, USEPA is proposing to repeal the mercury emission standard for existing lignite-fired EGUs of 1.2 pounds per trillion British thermal units of heat input (lb/TBtu) (the previous mercury standard, 4.0 lb/TBtu, would remain in place). Lastly, as an alternative to returning to the previous emissions standards, USEPA is requesting comment on cost-effective and achievable options that could replace the 2024 standards. The MATS proposal must go through a 45-day public comment period which began June 17, 2025.

CAA Section 111(b), Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units – New Source Performance Standards (NSPS) are established under Section 111(b) of the CAA for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the USEPA finalized an NSPS that established standards for emissions of carbon dioxide (CO_2) for newly constructed, modified, and reconstructed fossil-fuel fired EGUs. There are different standards of performance for fossil fuel-fired steam generating units and fossil fuel-fired combustion turbines.[3]

On May 8, 2024, USEPA finalized the NSPS that had been previously proposed in May 2023 for GHG emission reductions from new and reconstructed fossil fuel-fired stationary combustion turbine EGUs. For new fossil-fuel generation, the final rule includes three subcategories based on the utilization of each EGU.

[3] The 111(b) standards can be found in Table 1 here: https://www.federalregister.gov/documents/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary.

CAA Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources - Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the CAA requires the USEPA to establish standards for certain existing industrial sources. The final Clean Power Plan (CPP), promulgated on October 23, 2015, addressed CO_2 emissions from EGUs. The CPP established interim and final statewide goals and tasked states with developing and implementing plans for meeting the goals.

As described above, on May 8, 2024, USEPA finalized regulations under Section 111(d) of the CAA for GHG reductions for existing coal-fired EGUs as well as existing coal-fired power plants and other coal-fired steam generating units. The final rule establishes subcategories based on how long each unit is expected to operate. In addition, States are able to evaluate units in their fleet and provide a variance for units that will operate under different circumstances than those considered by USEPA based on "remaining useful life and other factors".

On June 11, 2025, the USEPA proposed to repeal the GHG emissions standards for fossil fuel-fired power plants promulgated under Section 111 of the CAA. With this action, the requirements USEPA has proposed to repeal include the NSPS for coal and gas-fired power plants, promulgated on October 23, 2015, the NSPS for coal-fired steam generating units undergoing a large modification, the NSPS for new natural gas-fired power plants finalized in the Carbon Pollution Standards (CPS) on May 9, 2024, and the emission guidelines for existing coal-, oil-, and gas-fired steam generating units, also finalized on May 9, 2024. This proposed rule is currently in the middle of a 45-day public comment period set to wrap up the end of summer. A final rule is currently expected to be released by USEPA before the end of 2025.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codified at 40 CFR Part 98) tracks facility-level emissions of greenhouse gas from large emitting facilities, suppliers of fossil fuels, suppliers of industrial gases that result in greenhouse gas emissions when used, and facilities that inject CO_2 underground. Facilities calculate their emissions using approved

methodologies and report the data to the USEPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year.

On March 12, 2025, the USEPA Administrator announced plans to reconsider the mandatory GHG reporting program on the basis that the program is costly and burdensome to the over 8,000 facilities required to calculate and submit their emissions reports annually. As of the end of June 2025, the proposed rule to reconsider and potentially repeal the GHG emissions reporting program was being reviewed by USEPA's Office of Management and Budget.

Boiler Maximum Achievable Control Technology – The Boiler MACT establishes national emission standards for HAPs from three major source categories: industrial boilers, commercial and institutional boilers, and process heaters. The final emission standards for control of mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and carbon monoxide (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers are based on the MACT. In addition, all major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

Regional Haze – Section 169 of the federal CAA sets forth the provisions to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country by establishing a national goal to remedy impairment of visibility in Class 1 federal areas from manmade air pollution. There are two Class 1 areas in Michigan: Seney National Wildlife Refuge and Isle Royale National Park. Michigan also has an obligation to eliminate the state's contribution to impairment in Class 1 areas in other states. States must ensure that emission reductions occur over a period of time to achieve natural conditions by 2064. Air pollutants that have the potential to affect visibility include fine particulates, NO_x, SO_2, certain volatile organic compounds, and ammonia. The 1999 Regional Haze rule required states to evaluate the best

available retrofit technology (BART) to address visibility impairment from certain categories of major stationary sources built between 1962 and 1977.

In 2005, the USEPA published the guidelines for BART determinations. Michigan met most of the initial BART determination requirements through its first planning period state SIP; however, USEPA did issue FIPs for three of Michigan's non-EGU BART-subject sources between 2012 and 2016. All BART determinations made for EGU sources in Michigan were approved by USEPA and adopted into the SIP.

In July 2024, USEPA released guidance for the second planning period progress report for regional haze. EGLE submitted its mid-term five-year progress report for the second planning period to USEPA on May 19, 2025. USEPA has yet to act on the submittal.

Resource Conservation and Recovery Act – The Resource Conservation and Recovery Act (RCRA) gives the USEPA the authority to control hazardous waste from the "cradle-to-grave", which includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.

On May 8, 2024, USEPA finalized changes to the CCR regulations for inactive surface impoundments at inactive electric utilities called "legacy CCR surface impoundments." The rule was finalized at the same time as a larger suite of regulations for power plants, some of which were mentioned above, and others will be mentioned below. The rules were finalized at the same time to allow utilities more certainty in future planning. Finalized CCR requirements mirror those previously completed in 2015 for inactive impoundments at active facilities. This part of the final rule responds to the August 2018 court decision vacating and remanding a provision of the 2015 CCR rule that exempted inactive impoundments at inactive electric utilities back to USEPA. The final rule also remedies concerns noted by USEPA once implementation of the 2015 CCR rule began.

Clean Water Act – The Clean Water Act is a United States federal law designed to control water pollution on a national level.

Clean Water Act Section 316(b) – The USEPA promulgated rules under Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at new and existing facilities in order to minimize the impingement and entrainment of fish and other aquatic organisms at these structures. Section 316(b) applies to existing electric generation facilities with a design intake flow greater than two million gallons per day that use at least 25% of the water withdrawn from the surface waters of the United States for cooling purposes.

According to the published rules, any facility subject to the existing facilities rule must identify which one of the seven alternatives identified in the best technology available (BTA) standard will be met for compliance with minimizing impingement mortality. While the rules do not specify a deadline for compliance of the rules, facilities will need to achieve the impingement and entrainment mortality standards as soon as practicable according to the schedule of requirements set by EGLE following NPDES permit reissuance.

Steam Electric Effluent Guidelines – The Steam Electric Effluent Guidelines (SEEG), promulgated under the Clean Water Act, strengthens the technology-based Effluent Limitation Guidelines (ELG) and standards for the steam electric power generating industry. The 2015 amendment to the rule established national limits on the amount of toxic metals and other pollutants that steam electric power plants are allowed to discharge.

Like USEPA's GHG regulations for existing coal-fired power plants and steam electric generating units and CCR, updated ELGs were promulgated in spring 2024. The updated regulations strengthen the wastewater discharge standards that apply to coal-fired power plants by establishing more stringent discharge standards for flue gas desulfurization wastewater, bottom ash transport water, and combustion residual leachate.

For those facilities that will be required to meet the more restrictive effluent limitations in the 2024 rule, the new limitations do not apply until a date determined by the permitting authority that is 'as soon as possible,' on or after July 8, 2024, but no later than December 31, 2029. The final rule also established a new subcategory for the permanent cessation of coal combustion by December 31, 2034.

In June 2025, USEPA announced that it plans to delay and potentially loosen the water standards for coal-fired power plants due to concerns with compliance deadlines and the need to strengthen grid reliability. In addition, the Secretary of Energy under section 202(c) of the Federal Power Act, 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), issued an order in May 2025 to the MISO to ensure reliability of its system over the following 90 days. That order specifically requests dispatch of the Campbell Plant to best meet the emergency reliability concerns and serve the public interest for purposes of FPA section 202(c) instead of proceeding with the scheduled decommissioning of the plant on May 31, 2025. Similar orders may be issued for this facility, or other facilities, which conflict with the compliance timelines of the existing ELGs.

One Big Beautiful Bill (OBBB) Act – The OBBB was signed into law on July 4, 2025. The OBBB accelerates the sunset for Wind and Solar under Sections 45Y and 48E, setting more strict timelines for beginning construction or in service dates. However, Hydropower, geothermal, energy storage, and nuclear retain full tax credits through 2033 with a phase out starting in 2034. Fuel Cells now qualify for a flat 30% ITC under Section 48E and the OBBB increases the domestic content bonus credit thresholds. The OBBB also impacts residential clean energy by ending the residential solar tax credit on all owned and leased residential systems by December 31, 2025 and December 31, 2027 respectively under 48 E. Leased residential solar hot water heaters and small wind turbines

installed after December 31, 2025 are no longer eligible. OBBB also adds tax credits for carbon capture and sequestration under Section 45Q.

State Rules and Laws:

The majority of Michigan's environmental regulations and laws were consolidated into the Natural Resources and Environmental Protection Act (NREPA) of 1994, PA 451 as amended (Act 451). Act 451 is organized into sections called "Parts" and serves "to protect the environment and natural resources of the state; to codify, revise, consolidate, and classify laws relating to the environment and natural resources of the state; to regulate the discharge of certain substances into the environment; to regulate the use of certain lands, waters, and other natural resources of the state; to protect the people's right to hunt and fish; to prescribe the powers and duties of certain state and local agencies and officials; to provide for certain charges, fees, assessments, and donations; to provide certain appropriations; to prescribe penalties and provide remedies; and to repeal acts and parts of acts."

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulate the emissions of mercury in the State of Michigan. Existing coal-fired EGUs must choose one of three methods to comply with the emission limits and any new EGU will be required to utilize Best Available Control Technology. The MMR is identical to the MATS in its limitations and all compliance dates for this rule have since past.

Michigan Environmental Protection Act – Part 17 of Michigan's NREPA, 1994 PA 451. Under Michigan Environmental Protection Act (MEPA), the general attorney or any person may maintain an action for an alleged violation or when one is likely to occur for declaratory and equitable relief against any person for the protection of the air, water, and other natural resources and the public trust in these resources from pollution, impairment, or destruction. MEPA also provides for consideration of environmental impairment and whether a

feasible and prudent alternative exists to any impairment consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment, or destruction.

Solid Waste Management (Part 115) – Part 115 of the Michigan NREPA regulates CCR as a solid waste. It requires any CCR that remain in place in a surface impoundment or landfill be subject to siting criteria, permitting, and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, corrective action, and financial assurance and post-closure care for a 30-year period. The disposal facility is required to maintain financial assurance to conduct groundwater monitoring throughout the post-closure care period.

The disposal facility is required to maintain financial assurance to conduct groundwater monitoring throughout the post-closure care period. The disposal of CCR is currently dually regulated under the RCRA rule published in April 2015, and under Part 115 of the NREPA. However, in December 2016, the Water Infrastructure Improvements for the Nation (WIIN) Act was passed, which included an amendment to Section 4005 of RCRA providing a mechanism to allow states to develop a state permitting program for regulationof CCR units. Under the amendment, upon approval of a state program, the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure. In 2018, Part 115 was amended to include that majority of the RCRA regulations would be enforced by states and that CCR units would not be subject to the dual regulatory structure. Michigan's request for state program approval has not yet been approved by USEPA. EGLE is currently working to revise the State program and plans to resubmit for USEPA's review and approval once complete.

Water Resource Protection (Part 31) – Part 31 of the Michigan NREPA grants EGLE authority to develop rules to protect waters of the state.

Water Quality Based Effluent Limits for Toxic Substances (Part 8) – Michigan's Part 8 Rules, Water Quality-Based Effluent Limit Development for Toxic Substances are used to establish toxic substance water quality based effluent limits (WQBELs) for point-source discharges that are protective of the designated uses of the surface waters of the state. Part 8 includes provisions for establishing total maximum daily loads, waste load allocations for toxic substances, reasonable potential for chemical-specific WQBELs, and calculating WQBELs that are less than the quantification level.

Water Quality Standards (Part 4) – Michigan's Part 4 Rules, Water Quality Standards, are used to establish water quality requirements applicable to the Great Lakes, the connecting waters, and all other surface waters of the state, to protect the health and welfare, to enhance and maintain the quality of water, and to protect the state's natural resources. Part 4 includes provisions for establishing specific standards for physical characteristics, dissolved solids, hydrogen ion concentrations, toxic substances, nutrients, microorganisms, dissolved oxygen, and temperature. It provides conditions for establishing mixing zones, antidegradation requirements, and variances from water quality standards, and defines the designated uses for which all surface waters of the state shall be protected.

To comply with PA 341 Section 6t (5) (m)

"How the utility will comply with all applicable state and federal environmental regulations, laws and rules, and the projected costs of complying with those regulations, laws and rules."

In developing its IRP, a utility should present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws, and rules. Included with this information, the utility should analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet, and include the relevant future compliance costs within the IRP model. Review and approval of an electric utility's IRP by

the MPSC does not constitute a finding of actual compliance with applicable state and federal environmental laws.

Executive Directive 2020-10 (ED 2020-10) – On September 23, 2020, Governor Whitmer signed an executive directive (ED 2020-10) establishing Michigan's plans toward carbon neutrality by 2050. ED 2020-10 also established an interim goal of a 28 percent reduction (below 2005 levels) in GHG emissions by 2025 and required EGLE's Office of Climate and Energy to develop, with stakeholder input the MI Healthy Climate Plan and then oversee implementation of the Plan.

The ED also directed EGLE to expand its IRP advisory opinion under MCL section 460.6t to include an evaluation of "the potential impacts of proposed energy generation resources and alternatives to those resources." An evaluation of whether the IRPs filed are consistent with the emission reduction goals established in the ED must also be completed. Lastly, the ED required EGLE's advisory opinions to include considerations of environmental justice and public health impacts.

Upon the signing of ED 2020-10, EGLE began working with the MPSC and utilities subject to the IRP process to develop a list of additional data requirements to better allow EGLE to complete the evaluations of environmental justice and public health impacts. These requirements were finalized in the IRP filing requirement document completed in the fall of 2022.

EGLE finalized the MI Healthy Climate Plan in April 2022 and has completed two annual reports since that time. The Plan detailed the pathway to obtaining 100 percent carbon neutrality by 2050 based on seven key objectives. The Plan's roadmap to 2030 provided key recommendations to reach the goal of reducing GHG emissions (from 2005 levels) by 52 percent by 2030. Some of the recommendations included in the Plan are to move the electric grid to cleaner resources, electrification of vehicles and increasing public transit, and the commitment to environmental justice and a just transition.

Public Act 231 (PA 231) – In November 2023, Governor Whitmer signed into law new energy legislation making changes to several aspects of Michigan's energy future, including IRPs. Public Act 231 (PA 231) includes updates to the IRP statute requiring an update to this IRP planning parameters document, IRP filing requirements, and adding additional considerations the Commission must review in its evaluation of each IRP. Most notably, this planning parameters document is required to be updated in 2025 and every four years thereafter. From the EGLE perspective, PA 231 codifies the additional data requirements necessary to complete a more thorough review of IRP documents from the environmental justice and public health perspectives. PA 231 has additional requirements applicable to the Commission, including opening a proceeding to consider expanding opportunities for public engagement in the Commission's proceedings and decision-making process, as well as proceedings to consider improving review of utility rate cases.

Public Act 235 (PA 235) – PA 235 established a clean energy standard of 80 percent by 2035 and 100 percent carbon neutrality by 2040. This moves up the energy transition ten years from ED 2020-10, where the 100 percent carbon neutrality goal was to be achieved by 2050. Clean energy plan format and guidelines are to be developed by the Commission by 2026, and utilities must submit plans no later than 2028. PA 235 also establishes a statewide energy storage target of 2,500 MW, with utilities required to submit plans to procure a proportional share of the statewide target by December 31, 2029. This act also establishes a renewable energy standard of 50 percent by 2030 and 60 percent by 2035. PA 235 also allows for an increase in the distributed generation program cap from one percent to ten percent and required a one-time upper peninsula energy study which is currently been completed by the Commission.

In addition to PA 231 and PA 235, the Governor also signed PA 229 and 233 impacting electric utilities into law. PA 229 established new energy waste

reduction targets and PA 233 created a voluntary siting process for significant renewable energy and energy storage facilities.

VII. Planning Reserve Margins and Local Clearing Requirements

To comply with PA 341 Section 6t (1) (e)

Compliance with Section 6t (1) (e) requires the identification of any required planning reserve margins and LCRs in areas of the state of Michigan. The majority of Michigan is part of the Midcontinent Independent System Operator (MISO). MISO is divided into local resource zones (LRZs or Zones) with the majority of the Lower Peninsula in Zone 7 and the Upper Peninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. The unshaded portion of the southwest area of the Lower Peninsula is served by the PJM regional transmission operator. While the PJM has similar reliability criteria to MISO, there are some differences in terminology and details.

MISO publishes planning reserve margins in its annual Loss of Load Expectation (LOLE) Study Report each November.[4] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2022 through 2031" for the entire footprint. MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report. The local reliability requirement is a measure of the planning resources required to be physically located inside a LRZ without considering any imports from outside of the zone in order to meet the reliability criterion of one day in ten years LOLE. The MISO LCR is defined as "the minimum amount of unforced capacity that is physically located within

[4] MISO 2024-2025 Loss of Load Expectation Study Report published on November 1, 2024 MISO One Voice Style Guide

the LRZ that is required to meet the LOLE requirement while fully using the Capacity Import Limit for such." The LCR for each LRZ is reported annually with the MISO planning resource auction results in April.[5]

For the southwest corner of the Lower Peninsula, in PJM's territory,[6] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[7] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin, on an installed capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similar to MISO's planning reserve margin, on an unforced capacity basis. PJM also specifies 27 Local Deliverability Areas, somewhat similar to MISO's LRZ. PJM publishes a Reserve Requirement Study[8] annually in October containing the requirements for generator owners and load serving entities within its footprint for the next ten years.

Electric utilities required to file IRPs under Section 6t are also required to annually make demonstrations to the MPSC that they have adequate resources to serve anticipated customer needs four years into the future, pursuant to Section 6w of PA 341. On September 15, 2017, in Case No. U-18197, the MPSC adopted an order establishing a capacity demonstration process in an effort to implement the State Reliability Mechanism (SRM) requirements of Section 6w. This order established SRM-specific planning reserve margin

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[5] MISO Planning Resource Auction results, April 2024

https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

[6] See Appendix C for a map of PJM Local Deliverability Areas.

[7] See Appendix C for a map of PJM Local Deliverability Areas.

[8] PJM Reserve Requirement Study, October 2021.

https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx

requirements for each electric provider in Michigan for the period of planning years 2018 through 2021. In an order issued on October 14, 2017, in Case No. U-18444, the MPSC initiated a proceeding to establish a methodology to determine a forward locational requirement, to establish a methodology to determine a forward planning reserve margin requirement, and to establish these requirements for planning year 2022. In addition to planning to meet the reliability requirements of the regional grid operator (MISO or PJM, as applicable), electric utility IRP filings should be consistent with the requirements of the SRM under Section 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VIII. Modeling Scenarios, Sensitivities and Assumptions

To comply with MCL 460.6t(1)(f)

For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, Scenario 1 is required, and Scenario 2 can be replaced with a utility created scenario if assumptions in Scenario 2 have changed such that they are no longer applicable. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multi-state IRPs in other jurisdictions. Due to the provisions in MCL 460.6t (4) regarding multi-state IRPs, Northern States Power-Wisconsin and Indiana Michigan Power Company are intentionally excluded from the explicit requirement to model the outlined scenarios. However, the multi-state utilities are encouraged to include the provisions included in each scenario. The Commission may request additional information from multi-state utilities prior to approving an IRP, pursuant to MCL 460.6t (4).

Scenario #1 (required)

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario directionally aligns with MISO's November most recently published Futures Report, Future 3a[9],[10]. This scenario incorporates 100% of utility IRP and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met across the MISO region. This scenario incorporates the retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 3a. A utility can adjust these retirements if those adjustments are supported by publicly available information or utility supported analysis. As subsequent MISO Futures Reports are released, the utility should adopt the updated retirement assumptions identified in the Future most aggressive carbon reduction future.

This scenario assumes significant advancements toward electrification that drives a total energy growth rate to 1.08% (or the growth rate specified in MISO's most recent Futures 3a) throughout the Eastern Interconnect.[11] Utilities should either assume EV adoption reaches 50% of total vehicle sales by 2030, with a trend toward 100% of vehicle sales continues throughout the remainder of the study period for both the eastern interconnect outside of Michigan and the Utility's service territory.[12] Alternatively, a utility may develop its own high growth assumptions for EV adoption, provided that the assumptions are supported by reputable source(s) either publicly available or commissioned studies by the utility whose assumptions and data can be made available for scrutiny. Using this information, utilities may develop their own demand and

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[9] The most recent MISO futures are published on the MISO website: https://www.misoenergy.org/planning/transmission-planning/futures-development/

[10] As MISO develops new futures, this scenario should align with MISO's most aggressive carbon reduction future. All 3a assumptions should then be updated accordingly.

[11] This high load growth is meant to capture both large scale industrial and manufacturing load growth as well as residential load growth. The utility can specify the drivers of this load growth with support if the utility finds it necessary to augment the MISO futures load assumptions.

[12] Note: This EV adoption rate applies to all vehicle types.

energy forecasts with description and detail of how their forecast has included the impacts of climate change,[13] electrification, demand side resources, and customer-owned distributed generation and how these factors impact overall load and demand.

Emissions decline driven by state goals and utility plans throughout the MISO footprint, creating an 80% carbon reduction (or the reduction included in MISO's most recent Futures 3 scenario) by 2042 across the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. If PJM provides no set goal, then utilities shall utilize carbon reduction goals set by their respective corporate entity. This trajectory of carbon reduction is expected to continue beyond 2042. Market energy transactions are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3a.[14]

- Natural gas prices utilized are consistent with the Reference Case projections from the United States EIA's most recent AEO.[15]
- Current DR, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they were economically selected by the model or to help comply with the specified carbon reductions in this scenario.

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[13] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[14] Scenario 1 aligns with MISO Future 3a from the November 2023 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.

[15] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and include delivery costs from Henry Hub to the point of delivery. Utilities may use a mixed 5-year future if the remainder of the forecast mirrors the EIA's most recent AEO.

- Consistent with the most recent MISO Future 3a, EV adoption and customer electrification increases causing adjustments in utility load profiles as electrification and EV's are adopted through the planning horizon.
- Electrification growth within the utility service territory and subsequent energy and demand impacts shall be informed by either established proprietary forecasts or publicly available data and account for utility customer trends. Assumed impacts of electrification on energy and demand forecasts shall be clearly delineated and identified in the utility filing. Utility electrification programs should be informed by the Statewide Electrification Study.
- A combination of new customer load and electrification are used to achieve the forecasted energy growth in this scenario. All contracted large load should be included in the utility's base load forecast and detailed in accordance with the Integrated Resource Plan Filing Requirements.
- Specific new units are modeled in the LRZ if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, signed GIA, Renewable Energy Plan, or Voluntary Green Pricing Plan) for units in the utility's resource zone only (e.g., DTE Electric's LRZ is MISO Zone 7).
- For an electric utility independently administering its own EWR program, load should be modeled based upon maintaining a 2.17% EWR savings.
- The EWR maximum achievable savings opportunity will be established in a potential study by the Michigan state-wide achievable potential with an average life of at least 8 years for EWR measures, at the portfolio level. If the utility is not already at 2.17%, ramp up the utility's EWR savings to at least 2.17% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the Michigan state-wide potential study for more aggressive potential.

- EWR savings remain at a minimum of 2.17% throughout the study period.[16] Additional cost effective EWR should be modeled. There should be no cap on EWR savings levels. There should be no cap on costs associated with EWR programs as long as the program portfolio is cost effective based on a UCT score of 1.0 or greater.
- New resource selection for the utility filing their IRP should align with the Company's REP and associated renewable portfolio standard, achieving 50% renewable energy by 2030 and 60% renewable energy by 2035. The plan developed using this scenario should illustrate how the Company plans to achieve the clean energy standard, 80% clean energy portfolio by 2035 and 100% clean energy portfolio by 2040.
- Existing renewable energy production and storage tax credits continue and renewable energy and storage investment tax credits continue, pursuant to current law. If the resource is eligible for Production Tax Credits (PTC) or Investment Tax Credits (ITC), the credit should be included in the modeling. Federal policy timing may impact modeling.
- Energy storage resources are modeled using available best practice methodologies and resources. Allow for multiple market revenue streams where applicable and demonstrate the utility is reasonably capturing the full value of storage. Utilize public, high resolution spatial and temporal data (e.g., related to costs and technologies) to improve the chronology of energy storage models and, if adequate public data is not available, use data that can be shared with parties through nondisclosure agreements. Utilize best practices to accurately model the operations of

[16] If there is not enough achievable savings potential to reach 2.17% of total retail electricity sales in megawatt hours in the preceding year, the maximum achievable potential found within the study will be modeled. The minimum energy savings should not be less than 1.5% of total retail electricity sales in megawatt hours in the preceding year. All scenarios will have an average life of at least 8 years for EWR measures, at the portfolio level, pursuant to Public Act 295 of 2008 as amended by Public Act 229 of 2023, Sec. 77.

long-duration and multi-day energy storage technologies and their participation in markets.

- Technology costs and limits to the total resource amount available for EWR and DR programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research as well as by the actual experience of EWR programs in Michigan.
- Existing Public Utility Regulatory Policies Act (PURPA) qualifying facilities (QFs), up to the utility's "must buy" obligation MW threshold, are assumed to be renewed, unless the QF indicates otherwise, either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract, unless the QF indicates otherwise, either publicly or directly to the utility.
- Achieve and maintain energy storage resources necessary to meet the utility's proportional share of the minimum statewide energy storage target using the calculation methodology approved by the Commission in Case No. U-21571. Modeling should support the selection of energy storage technologies and other details of the utility's energy storage resource portfolio in the PCA.
- If the utility is planning on adding a non-clean resource, defined as any electric generating resource that does not qualify as a "clean energy system" or "renewable energy resource" under Act 295, as amended, or the MPSC's Clean Energy Plan Filing Requirements, it must model the scenario without the non-clean resource as well.

Scenario #1 Sensitivities:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent

EIA Low Oil and Gas Supply forecast natural gas fuel price projections (or other publicly available sources) by the end of the 20-year study period.

2. Model a renewable resource build constraint consisting of an unexpected 20% reduction from the utility's base assumption. This represents a limited ability to procure or construct renewable resources in the first 6 years of the plan within Michigan. Then allow the model to supplement the utility's renewable shortfall with out-of-state resources that comply with MCL 460.1028(5), and assess any constraints on replacement resources. This should include implementation risks for any out-of-state resources or thermal resources selected by the model that would replace in-state constrained resources.
3. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.
4. The utility should create a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model.
5. Model a sensitivity whereby the model caps the utility's land based renewable portfolio at 60% and the remaining resource needs to meet the clean energy plan are achieved through the procurement of other technologies including but not limited to off-shore wind, out-of-state wind, advanced nuclear reactors, natural gas with carbon capture and sequestration, other resources that the Commission may determine qualify as clean energy systems pursuant to MCL 460.1003(i). This sensitivity should include a narrative detailing any implementation risks for the other technology resources.
6. Model the presence of distributed generation resources at a maximum limit provided for in MCL 460.1173 as well as at 15% and 20% of the utility's 5-year average annual peak load.

7. Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions.

Scenario #2

Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7 (encouraged for multi-state utilities).[17]

This scenario directionally aligns with MISO's most recently published Futures Report, Future 1a and reflects substantial achievement of state and utility announcements, including generation retirements and environmental goals. This scenario incorporates 100% of utility IRP retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. For the utility performing the analysis, the generation unit retirement assumptions may vary from the MISO Futures Report only for the thermal generation units that the utility has decision making authority or for any unit retirements that have been publicly announced since publication of the MISO report. The filing utility may incorporate more recently announced retirements if practical. As subsequent MISO Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 1a of the November 2023 report should be used.[18] This scenario assumes that CO_2 emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating a target of 40% carbon reduction by 2042[24] from the baseline year of 2005 for the MISO region. Carbon emissions continue to decline on this trajectory beyond 2040.

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[17] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $4.27/MMBtu in 2040.

[18] Scenario 2 aligns with MISO Future 1a from the November 2023 MISO Futures Report. If, in the future, MISO Futures significantly change in future reports, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 2.

This scenario assumes annual energy growth of 0.22%, driven by existing economic factors, with moderate electric vehicle (EV) adoption and customer electrification, resulting in moderate MISO footprint-wide demand and energy growth rates. Utilities may use the most recent United States Energy Information Administration (EIA) Annual Energy Outlook (AEO) Reference Case or other reputable source for forecasted EV adoption rates. If the utility does not use EIA AEO, then the EV forecast information must be provided within the utility IRP filing. Using this information, a utility may develop its own demand and energy forecasts with description and detail how its forecast has included the impacts of climate change, [19] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand. The utility can use alternative load growth assumptions to the extent that they are fully supported by publicly available data.

- Natural gas prices utilized are consistent with Reference Case projections from the United States EIA's most recent AEO. [20]
- Moderate EV adoption and customer electrification result in moderate MISO footprint-wide demand and energy growth. Within Michigan, EV and electrification forecasts should be blended with historical sales such that after three years, Michigan's load and demand increase reflects the source forecasts for EV and electrification technologies. Utility load profiles of EVs and electrification technologies should be clearly delineated and presented individually such that it is clear how they each

[19] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[20] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars, including delivery costs from Henry Hub to the point of delivery.

impacted the overall energy and demand forecast. EV forecasts maybe based off the Reference Case in the most recent EIA AEO.

- Electrification growth within the utility service territory and subsequent energy and demand impacts shall be informed by either established proprietary forecasts or publicly available data and account for utility customer trends. Assumed impacts of electrification on energy and demand forecasts shall be clearly delineated and identified in the utility filing. Utility electrification programs should be informed by the Statewide Electrification Study.
- Resource assumptions: MISO Future 1a retirements for existing thermal and nuclear generation resources published in the most recent Futures Report should be used when available. The filing utility may incorporate more recently announced retirements if practical. Specific new units will be modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), IRP cost pre-approval, or signed generator interconnection agreement (GIA)). In the absence of a MISO defined retirement assumption, maximum age assumption by resource type, as specified by applicable regional transmission organization (RTO), can also be used. Generic new resources are assumed to be consistent with the scenario description, considering anticipated new resources currently in generation interconnection queue, and should be chosen based upon economics and reliability.
- New resource selection for the utility filing their IRP should align with the Company's REP and associated renewable portfolio standard, achieving 50% renewable energy by 2030 and 60% renewable energy by 2035. The plan developed using this scenario should illustrate how the Company plans to achieve the clean energy standard, 80% clean energy portfolio by 2035 and 100% clean energy portfolio by 2040.
- For an electric utility independently administering its own EWR program, load should be modeled based upon maintaining a 1.5% EWR savings.

- The EWR maximum achievable savings opportunity will be established in a potential study by the Michigan state-wide achievable potential with an average life of at least 8 years for EWR measures, at the portfolio level.
- This scenario assumes that a utility maintains a minimum of 2.17% EWR savings throughout the study period.[21] Additional cost effective EWR should be modeled. There should be no cap on EWR savings levels. There should be no cap on costs associated with EWR programs as long as the program portfolio is cost effective based on a UCT score of 1.0 or greater.
- Energy storage resources are modeled using the best available practice methodologies. Allow for multiple market revenue streams where applicable and demonstrate the utility is reasonably capturing the full value of storage. Utilize public, high resolution spatial and temporal data (e.g., related to costs and technologies) to improve the chronology of energy storage models and, if adequate public data is not available, use data that can be shared with parties through nondisclosure agreements. Utilize best practices to accurately model the operations of long-duration and multi-day energy storage technologies and their participation in markets.
- Technology costs for thermal units and wind track with mid-range industry expectations.
- Technology costs and limits to the total resource amount available for EWR and DR programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.

[21] The minimum energy savings should not be less than 1.5% of total retail electricity sales in megawatt hours in the preceding year. All scenarios will have an average life of at least 8 years for EWR measures, at the portfolio level, pursuant to Public Act 295 of 2008 as amended by Public Act 229 of 2023, Sec. 77.

- Technology costs for solar, storage, and other emerging technologies decline with commercial experience, consistent with National Renewable Energy Laboratory (NREL) or other publicly available reputable sources.
- Existing PTC and ITC tax credits continue, pursuant to current law, and should be included in the modeling. Federal policy timing may impact modeling.
- Technology costs and limits to the total resource amount available for EWR and DR programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research as well as by the actual experience of EWR programs in Michigan.
- Existing Public Utility Regulatory Policies Act (PURPA) qualifying facilities (QFs), up to the utility's "must buy" obligation MW threshold, are assumed to be renewed, unless the QF indicates otherwise, either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract, unless the QF indicates otherwise, either publicly or directly to the utility.
- Achieve and maintain energy storage resources necessary to meet the utility's share of the statewide energy storage target using the calculation methodology approved by the Commission in Case No. U-21571. Modeling should support the selection of energy storage technologies and other details of the utility's energy storage resource portfolio in the PCA.

Scenario #2 Sensitivities:

1. Fuel cost: Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast.[22]

2. Load projections:

    a. High load growth: For the filing utility's load obligation, increase the energy growth rate by at least a factor of two above the base case energy or 0.5% (whichever is larger, but independent of any load growth from data centers) on a per customer basis. Adjust demand accordingly. For the region included in the scenario utilize load growth that is consistent with the most recent MISO futures.

    b. Low load growth: EV adoption and electrification are slower than expected. A utility may develop its own low load growth assumptions for EV adoption, provided that the assumptions are reasonably supported by reputable source(s) either publicly available or commissioned studies by the utility.

3. If the utility is not already achieving 2.17% EWR, ramp up the utility's EWR savings to at least 2.17% of prior year sales over the course of three years within the utility's Michigan jurisdiction.[23] EWR savings remain at 2.17% throughout the remainder of the study period.

4. The utility should create a low, medium, and high large load forecast that reflects expected large load growth based upon probabilistic weighting of known interested large loads. This forecast is in addition to the utility's base

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[22] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $4.27/MMBtu in 2040.

[23] 2025 Energy Waste Reduction Potential Study

load forecast. This sensitivity should reflect the resulting resource needs for incorporating a low, medium, and high large load growth forecast into the utility's model.

5. Model the impact of atypical weather conditions that occur at least as frequently as once in ten years in the least cost resource optimization, including how atypical weather can factor in unit derates, resource availability, and potential supply disruptions.

IX. Michigan IRP Modeling Input Assumptions and Sources

The following IRP modeling input assumptions and sources are recommended to be used in conjunction with the descriptions of the scenarios and sensitivities.

	Value	Sources
1 - Analysis Period	• A minimum analysis period of 20 years, with reporting for years 5,10, and 15 at a minimum as specified in the statute.	
2 - Model Region	• The minimum model region includes the utility's service territory, with transmission interconnections modeled to the remainder of Michigan, adjacent Canadian provinces if applicable. A larger model region is preferable, including the applicable RTO region as deemed appropriate by utility.	
3 - Economic Indicators and Financial Assumptions (e.g., Weighted Average Cost of Capital)	• Utility-specific	• Prevailing value from most recent MPSC proceedings
4 - Load Forecast	• 50/50 forecast • Forecasts other than 50/50 utilized to align with scenario and/or sensitivity descriptions should be documented and justified.	• Utility forecast and applicable RTO forecasts
5 - Unit Retirements	• Retirements driven by maximum age assumption or economics • Public announcements on retirements	• MISO or PJM documented fuel type retirements • All retirement assumptions must be documented • Retirement assumptions throughout the MISO footprint are consistent with MISO futures development Future 1a and Future 3a.
6 - Natural Gas Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/or sensitivity descriptions; Gas prices should include transportation costs.	• NYMEX futures (applicable for near-term forecastsonly) • EIA Annual Energy Outlook • EIA Table 3: Energy Prices • EIA Short-Term Energy Outlook Reports • If utility-specific data is utilized, it should be justified and made available to all intervening parties.

7 - Coal Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/or sensitivity descriptions; Coal prices should include transportation costs.	• EIA Coal Production and Minemouth Prices by Region • EIA Annual Energy Outlook • EIA Table 3: Energy Prices • EIA Short-Term Energy Outlook Reports/AnnualReports • If utility-specific data is utilized, it should be justified and made available to all intervening parties.
8 - Fuel Oil Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/or sensitivity descriptions.	• If utility-specific data is utilized, it should be justified and made available to all intervening parties.
9 - EWR Savings MWhs	Scenario #1: • For an electric utility independently administering its own EWR program, load should be modeled based upon maintaining a 2.17% EWR savings, If the utility is not already at 2.17% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the Michigan state-wide potential study for more aggressive potential. • For non-incentive earning electric utility, mandated annual incremental savings (1.5%) as a net to load. Scenario #1 Sensitivities: • For an electric utility independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction. Scenario #2**:** • For an electric utility independently administering its own EWR program, load should be modeled based upon maintaining a 1.5% EWR savings. • Consider load shape of EWR measures so on-peak capacity reduction associated with EWR can be reflected. Scenario #2 Sensitivities: • If the utility is not already achieving 2.17% EWR, ramp up the utility's EWR savings to at least 2.17% of prior year sales over the course of three years within the utility's Michigan jurisdiction. EWR savings remain at 2.17% throughout the remainder of the study period.	• Utility EWR plan and reconciliation filings • 2024/5 Energy Waste Reduction Potential Study • Other pertinent studies and research used by the utility.

10 - EWR Costs nominal dollars per kWh (Program administrator costs only; participant costs are not to be included in this analysis.)	• Current average levelized costs, as defined in 2021 EWR Potential Study, and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• Utility EWR plan and reconciliation filings • 2024/5 Energy Waste Reduction Potential Study • Other pertinent studies and research used by the utility.
11 - DR Savings MWs	• MWs by individual program (e.g., residential peak pricing, residential time-of-use pricing, residential peak time rebate pricing, residential programmable thermostats, residential interruptible air, industrial curtailable, industrial interruptible, etc.) or program type and class (e.g., residential behavioral, residential direct control, commercial pricing, volt/ Volt-Amp Reactive (VAR) optimization). • Technical, economic, and achievable levels of DR as applicable to the scenario.	• As defined by 2024/5 Demand Response Potential Study
12 - DR Costs nominal dollars per MW	• Costs/MW by program, including all payments, credits, or shared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2024/5 Demand Response Potential Study
13 - Renewable Capacity Factors	• Should be based on MISO seasonal capacity construct.	• If utility-specific data is utilized, it should be justified and made available to all intervening parties.

14 - Renewable Capital Costs and Fixed O&M Costs nominal dollars per kWh and Renewable Fixed O&M Costs nominal dollars per kW	• Wind, solar, biomass, landfill gas • Combined heat and power (CHP)	• National Renewable Energy Lab's *Annual Technology Baseline Report* • Department of Energy's *Wind Technologies Market Report* • Lawrence Berkeley National Lab's *Tracking the Sun* and *Utility Scale PV Cost* • Assumptions based on utility experience (Michigan specific and/or RTO - MISO/PJM) • 2015 Michigan Renewable Resource Assessment • Department of Energy's *Wind Vision Study* • Department of Energy's *Sunshot Vision Study* • Lazard's Levelized Cost of Storage Analysis 2.0 • If utility is using specific data not publicly sourced, mustbe justified and made available to all intervening parties.
15 – Fossil and Nuclear Generation nominal dollars per kW nominal dollars per kWh	• Combustion Turbine • Combined Cycle • Reciprocating Internal Combustion Engine • Carbon Capture and Sequestration • Nuclear, including Small Modular Reactor	US Energy Information Administration AEO2023 Cost and Performance Characteristics of New Generating Technologies
16 – Storage	• Achieve and maintain energy storage resources necessary to meet the utility's share of the statewide energy storage target using the calculation methodology approved by the Commission in Case No. U-21571. Modeling should support the selection of energy storage technologies and other details of the utility's energy storage resource portfolio in the PCA.	• LDES National Consortium • Lazard's Levelized Cost of Storage Analysis 9.0 • PNNL's Energy Storage Cost and Performance Database • Commission's Study of Long-Duration and Multi-Day Energy Storage Systems
17 – Other Resources	• Changes to operation guides • Options which improve reliability (Storage, SVC, HVDC, CVR) • Utilities shall take into account small qualifying facilities (20 MW and under) and other aggregated demand-side options as part of establishing load curves and future demand. Larger renewable energy resources, combined heat and power plants, and self-generation facilities (behind-the-meter (BTM) generation) that consist of resources listed below or fossil fueled generation should be considered in modeling, either as discrete projects, where such have been developed/defined, or as generic blocks of tangible size (e.g., 100 MW wind farm) where not yet defined. • Utility-scale (e.g., integrated gasification combined cycle, CHP, pumped hydro storage, other storage, voltage optimization) • BTM (customer BTM) Generation (e.g., solar photovoltaic (PV), biogas (including anaerobic digesters), CHP (combustion turbine,steam, reciprocating engines), customer-owned backup generators, microturbines (with and without cogeneration),fuel cells (with and without cogeneration), small-scale Reciprocating Internal Combustion Engine (RICE) units (with and without cogeneration)) • Other Distributed Resources (e.g., stationary batteries, electric vehicles, thermal storage, compressed air, flywheel, solid rechargeable batteries, flow batteries).	• Assumptions and parameters other than costs that are associated with the technologies and options (such as future adoption rates) should be afforded flexibility due to those technologies' and options' presently unconventional nature. However, the utility should still show that all assumptions and parameters are reasonable and were developed from credible sources. • Utilities shall use cost and cost projection data from publicly available sources or the utility's internal data sources. The utility must show that their data and projection sources are reasonable and credible. • State of the Art Practices for Modeling Storage in Integrated Resource Planning. • Charging Ahead: Energy Storage Guide for Policymakers • Advanced Energy Storage in Integrated Resource Planning. • Energy Storage in Integrated Resource Plans • Michigan Energy Storage Roadmap

18- Wholesale Electric Prices		• Documentation for wholesale price forecast must be provided to all intervening parties.
19 – Electric Vehicle Forecasts	Scenario 1 EIA AEO Reference Case Scenario 2 half of vehicle sales are electric by 2030	• EIA AEO Transportation
20- Electrification Forecasts	Utility electrification programs should be informed by the Statewide Electrification Study. Electrification growth within the utility service territory and subsequent energy and demand impacts shall be informed by either established proprietary forecasts or publicly available data and account for utility customer trends. Assumed impacts of electrification on energy and demand forecasts shall be clearly delineated and identified in the utility filing.	• 2024/5 Electrification Potential Study

X. Additional IRP Requirements and Assumptions

1. Prices and costs should be expressed in nominal dollars.
2. Models should account for operating costs and locational, capital and performance variations. For example, setting pricing for different tranches if justified.
3. Capacity factors should be projected based on demonstrated performance, consideration of technology improvements and geographic/locational considerations. Additional requirements for renewable capacity factors are described in the Michigan IRP Modeling Input Assumptions and Sources in the previous section of this draft.
4. For purposes of IRP modeling, forecasted energy efficiency savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiency cost and savings on an hourly basis. It is this aggregation and forecast of energy efficiency, to be acquired on an hourly basis that allows EWR to be modeled as a resource in an IRP for planning purposes.
5. Prior to modeling Scenario 1 and Scenario 2, the utilities shall consider and prescreen all the technologies, resources, and generating options listed in the Michigan IRP Modeling Input Assumptions and Sources in the previous section of this draft. These findings will then be presented and discussed via at least one stakeholder meeting with written comments from

stakeholders taken into consideration. The options having potential viability are then considered in modeling.

6. Consider all supply and demand-side resource options on equal merit, allowing for special consideration for instances where a project or a resource need requires rapid deployment.
7. In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall clearly identify all unit retirement assumptions and unless otherwise specified in the required scenarios, the utility has flexibility to allow the model to select retirement of the utility's existing generation resources, rather than limiting retirements to input assumptions.
8. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the NPVRRs. The utility should explicitly identify revenues that are expected to be earn that are offsets to the NPVRRs and the assumptions that those revenues are based upon.

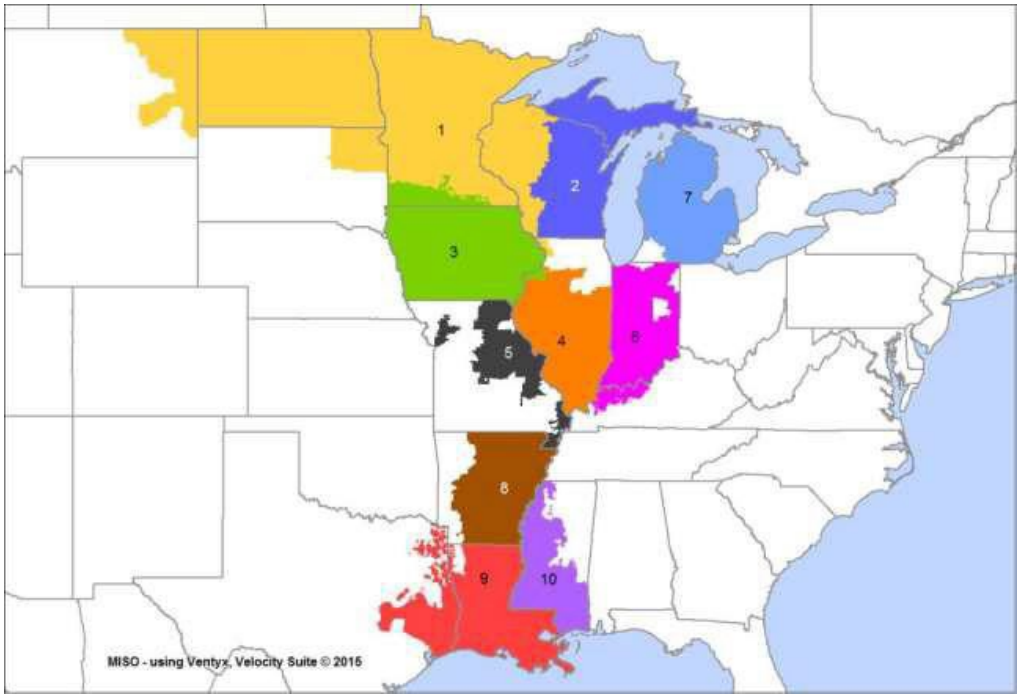
Appendix A: Organization Participation List

- Adams BioProcess Services
- Advanced Energy Economy
- American Council for an Energy-Efficient Economy
- American Electric Power
- American Municipal Power
- American Transmission Company
- Apollo Energy
- Armada Power
- Association of Businesses Advocating Tariff Equity
- Association of Energy Engineers
- Atlantic Council
- Attorney General
- Bay City Light & Power
- Bedrock Group
- Brattle Group
- Burns & McDonnell
- Cadmus Group
- Center Point Energy
- Charge Point
- Charthouse Energy
- Citizen Utility Board of Michigan
- City of Ann Arbor
- City of Grand Rapids
- City of Marquette
- Clark Hill
- Clean Grid Alliance
- CMS Energy
- Coalitions for Energy Efficient Logistics
- Consumers Energy
- CPower Energy Manager
- Dimension Renewable Energy
- DNV GL
- Dominion Energy
- Driftless Energy
- DTE Electric
- Duke Energy
- Dykema
- Earth Justice
- Ecology Center
- Dept. of Environment, Great Lakes & Energy
- Energy Exemplar
- Environmental Law & Policy Center
- EPRI
- Fein Solutions
- Five Lakes Energy
- Ford Motor Company
- Fraser Trebilcock Davis & Dunlap
- Futures Energy Group
- Great Plains Institute
- Grand Rapids Chamber of Commerce
- Grand Rapids Resident
- Grid Lap
- Guidehouse
- Hawk Utility Consulting
- Hecate Energy

- ICF New York University
- IFC
- Indiana Michigan Power
- ITC Holdings
- Key Capture Energy
- Lawrence Berkley National Laboratory
- Mi Air Mi Health
- Michigan Biomass
- Michigan Chemistry Council
- Michigan Climate Action Network
- Michigan Clinicians for Climate Action
- Michigan Conservative Energy forum
- Michigan Electric and Gas Association
- Michigan Electric Cooperative Association
- Michigan Energy Innovation Business Council
- Michigan Environmental Council
- Michigan Environmental Justice Coalition
- Michigan Farm Energy Program
- Michigan League of Conservation Voters
- Michigan Power Purchasers Association
- Michigan State University
- Michigan Townships Association
- Midcontinent Independent System Operator
- Milligan Grid Solutions
- Minnesota Public Utility Commission
- National Renewable Energy Laboratory
- Natural Resource Defense Council, Inc.
- Natural Resources Research Institute
- New Energy Advisors, LLC.
- Next Energy
- Northern States Power
- NRG Business Solutions, LLC.
- Oakridge National Laboratory
- Opower
- PACE Financing
- Pacific Northwest National Laboratory
- PJM
- Plugged in Strategies
- Policy Advisor Michigan House of Representatives
- Potomac Law Group
- PSC Healthy Energy
- Public Sector Consultants
- Public Utilities Commission of Ohio
- Purdue University Forecasting Group
- Ranger Power
- Regulatory Assistance Project
- Renewable Energy Buyers Alliance

- Renewable Energy Systems
- Rivenoak Consulting
- Ruben Strategy Group
- Siemens
- Sierra Club
- Spark Building Energy Solutions
- Sun 5 Repowering
- Sunrun
- The Healthy Homes Coalition of West Michigan
- Traverse City Light and Power
- Union of Concerned Scientists
- United States Energy Association
- University of Michigan
- Soulardarity
- Upper Peninsula Power Co.
- Urban Core Collective
- US Climate Alliance
- Varnum Law
- Vote Solar
- Walker Miller Energy
- Wartsila
- WEC Energy Group
- Wisconsin Public Service Commission
- Wolverine Electric Cooperative
- Wolverine Power
- Xcel Energy

Appendix B: Map of MISO Local Resource Zones



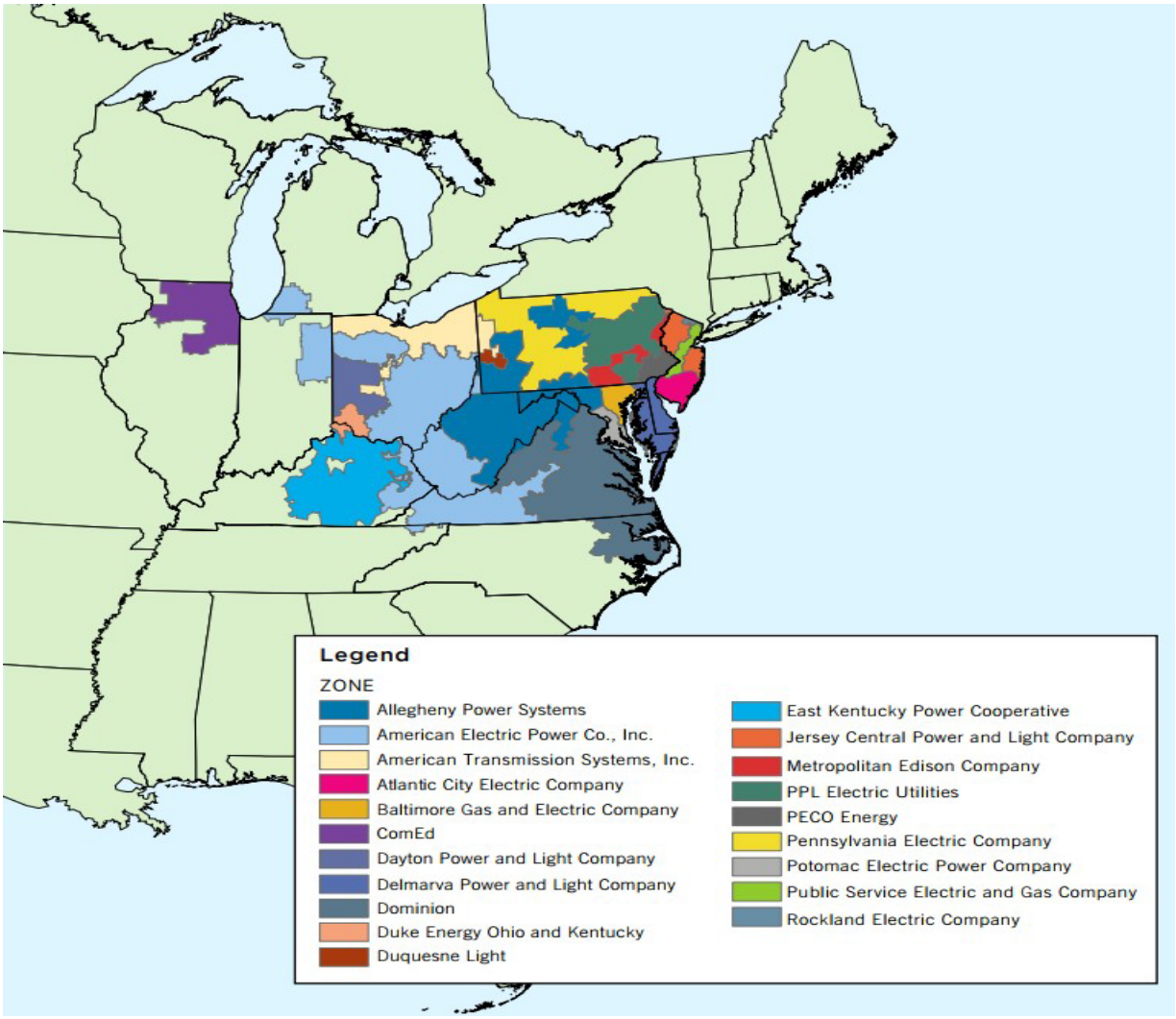
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

MISO Zone 2 - Rate regulated electric utilities - Upper Michigan Energy Resources Corporation and Upper Peninsula Power Company

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers Energy Company, and DTE Electric Company

PJM (Southwest Michigan) - Rate regulated electric utility - Indiana Michigan Power Company

Appendix C: Map of PJM Local Deliverability Areas



PJM (Southwest Michigan) - Rate regulated electric utility - Indiana Michigan Power Company is part of the American Electric Power Co., Inc.

Appendix D: Public Act 341 of 2016, Section 6t (1)

Section 6t (1) The commission shall, by August 31, 2025, and every 4 years thereafter, commence a proceeding and, in consultation with the department of environment, Great Lakes, and energy, and other interested parties, do all of the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state.

(b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment must expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills.

(c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.

(d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.

(e) Identify any required planning reserve margins and local clearing requirements in areas of this state.

(f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:

(i) Any required planning reserve margins and local clearing requirements.

(ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

(iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, projected load impact due to electrification, and projected load management and demand response savings.

(iv) Any regional infrastructure limitations in this state.

(v) The projected costs of different types of technologies and fuel used for electric generation.

(g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios or assumptions.

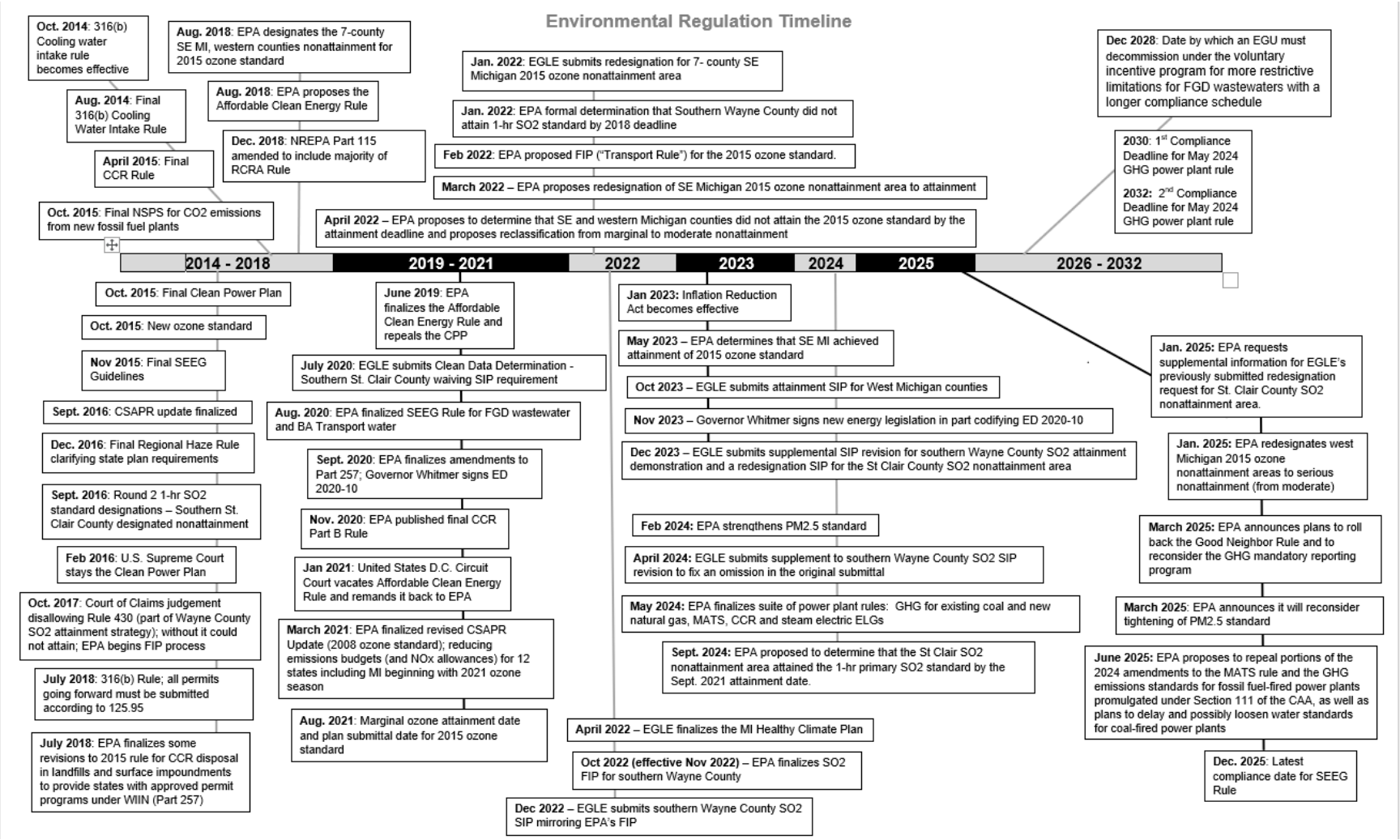
(h) Publish a copy of the proposed modeling scenarios and assumptions to be used in integrated resource plans on the commission's website.

(i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.

(j) Conduct an assessment of the potential for electrification of transportation, buildings, and industries consistent with economy-wide elimination of greenhouse gas emissions in this state, based on what is economically and technically feasible, as well as what is reasonably achievable.

(k) Identify environmental justice communities.

Appendix E: Environmental Regulatory Timeline



Appendix F: Acronyms

ACE: Affordable Clean Energy

AEO: Annual Energy Outlook

BA: Bottom Ash

BART: Best Available Retrofit Technology

BTA: Best Technology Available

BTM: Behind the Meter

CAA: Clean Air Act

CCR: Coal Combustion Residual

CDD: Clean Data Determination

CHP: Combined Heat and Power

CON: Certificate of Necessity

CO_2: Carbon Dioxide

CPP: Clean Power Plan

CSAPR: Cross-State Air Pollution Rule

DR: Demand Response

DSMSim™: Demand Side Management Simulator

EGLE: Department of Environment, Great Lakes, and Energy

EGU: Electric Generating Units

EIA: Energy Information Administration

ELG: Effluent Limitation Guidelines

EWR: Energy Waste Reduction

EV: Electric Vehicle

FGD: Flue Gas Desulfurization

FIP: Federal Implementation Plan

GIA: Generator Interconnection Agreement

HAP: Hazardous Air Pollutants

HVDC: High Voltage Direct Current

IRP: Integrated Resource Plan

LCR: Local Clearing Requirement

LOLE: Loss of Load Expectation

LRZ: Local Resource Zones or Zones

MACT: Maximum Achievable Control Technology Standards

MAE: Michigan Agency for Energy

MATS: Mercury and Air Toxic Standards

MDEQ: Michigan Department of Environmental Quality

MEPA: Michigan Environmental Protection Act

MIRPP: Michigan Integrated Resource Planning Parameters

MISO: Midcontinent Independent System Operator

MMR: Michigan Mercury Rule

MPSC: Michigan Public Service Commission or Commission

MW: Megawatts

MWh: Megawatt Hour

NAAQS: National Ambient Air Quality Standards

NO_x: Nitrogen Oxide

NPDES: National Pollutant Discharge Elimination System

NPVRR: Net Present Value Revenue Requirement

NREL: National Renewable Energy Laboratory

NREPA: Natura Resources and Environmental Protection Act

NSPS: New Source Performance Standards

PA: Public Act

Ppb: Parts per Billion

PURPA: Public Utility Regulatory Policies Act

PV: Photovoltaic

QF: Qualifying Facility

RCRA: Resource Conservation and Recovery Act

RICE: Reciprocating Internal Combustion Engine

RTO: Regional Transmission Organization

SEEG: Steam Electric Effluent Guidelines

SIP: State Implementation Plan

SO_2: Sulfur Dioxide

SRM: State Reliability Mechanism

UCT: Utility Cost Test

USEPA: United States Environmental Protection Agency

USWAG: Utility Solid Waste Activities Group

VAR: Volt- Amp Reactive

WIIN: Water Infrastructure Improvements for the Nation

Appendix G: Minimum Scenario and Sensitivities Required for Retirement Analysis

	Build Plans					
	PCA	Utility Alternative	Previous Approved IRP PCA Retirement Dates	Retirement Decision A	Retirement Decision B	Retirement Decision C
Scenario #1 (required)						
Base Scenario	X	X	X	X	X	X
1. High Gas Price	X	X		X	X	X
2. Renewable Constraints	X	X		X	X	X
3. 2.5% EWR	X	X				
4. Hydrogen Policy	X	X				
5. Offshore Wind Policy	X	X				
6. Nuclear Policy	X	X				
Scenario #2 (or utility replacement)						
Base Scenario	X	X	X	X	X	X
1. High Gas Price	X	X		X	X	X
2. a. High Load Growth	X	X		X	X	X
2. b. Low Load Growth	X	X				
3. 2.17% EWR	X	X				

The intent of this matrix is to allow for a robust comparison of the final PCA, any utility proposed alternative, and retirement decisions across many futures. The matrix will provide an understanding of how the proposed build plans will respond in when forced into the two scenarios and sensitivities. Additionally, this matrix is intended to illustrate the utility's retirement decision is the most reasonable and allow for each retirement decision to be evaluated independently and collectively to the extent that the utility chooses to include the retirement in its PCA.

This matrix is designed to show the minimum scenarios and sensitivities that a final PCA, utility proposed alternative, and retirement decision should be evaluated. The scenario number and sensitivity number correspond to the MIRPP scenarios and sensitivities detailed in this document. The retirement decisions identified as Retirement Evaluation A, B, C above is meant to represent the different retirement decisions a utility may be evaluating within the IRP. For example, if a utility proposes a retirement be included in the PCA, the evaluation of that decision would be the opposite, i.e. the build plan without the retirement.

Notes:

1. Utility Alternative is only necessary to the extent that the utility is proposing an alternative to its PCA in its filing.
2. For the previously approved IRP Retirement Date runs The previously approved PCA retirement dates should be fixed in the model and the model allowed to reoptimize for the optimal resources. This is done to isolate the effect that changes in retirement date have on the overall build plan when compared with previously approved retirement dates.

Revised
Integrated Resource Plan
Filing Requirements

U-21570 & U-21867

Pursuant to Public Act 341 of 2016, Section 6t

December 18, 2025

Application Instructions for Integrated Resource Plan Filings

These application instructions apply to a standard electric utility application for Michigan Public Service Commission (MPSC or Commission) approval of an Integrated Resource Plan (IRP) under the provisions of MCL 460.6t, as well as an IRP that may be filed under the provisions of MCL 460.6s.[1] The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the utility may also be included in the application.

Schedule

A utility shall coordinate with the Commission Staff (Staff) in advance of filing its application to avoid resource challenges with IRP applications being filed at the same time as IRP applications filed by other utilities. A utility may be requested to delay its IRP application to preserve a 21-day spacing between IRP applications.

Following the initial IRP applications, the utilities shall comply with all future filing deadlines directed by the Commission and shall continue to coordinate with the Staff to schedule future IRP application filing dates.

Filing Announcement

To facilitate the scheduling and preparation of IRP proceedings, a utility shall file a filing announcement in a new docket at least 30 calendar days prior to the expected or scheduled filing date. A utility who intends to file an IRP on a date other than its scheduled filing date, shall file a filing announcement, in a new docket, at least 30 calendar days prior to the proposed filing. The filing announcement, along with proof of service, shall be served on all parties granted intervention in the utility's last IRP case and the utility's last electric rate case. If the IRP described in the filing announcement is not filed within 120 days after filing of the announcement, the filing announcement will be considered withdrawn. The IRP filing announcement will also serve as the CEP filing announcement. If a certificate of necessity (CON) is also being filed; the same filing announcement will serve as the filing announcement

[1] Variations from the standard instructions may occur as allowed by MCL 460.6t(4) for multistate utilities and those serving fewer than 1 million Michigan customers.

required for the CON.

The filing announcement shall include:

a) Statement of intent to file an IRP;
b) Estimated date of filing;
c) Information related to any stakeholder engagement meetings that have already taken place or are scheduled to take place;
d) Information related to any CON application that would be filed with the utility's IRP; and
e) Information related to the CEP that will be filed with the utility's IRP.[2]

The Commission may, if necessary, order a delay in filing an application to establish a 21-day spacing between filings. The filing announcement shall be submitted at least 30 calendar days prior to the IRP application, thus providing the Commission sufficient time to issue an order regarding the 21-day spacing, if it so chooses.

Pre-Filing Request for Proposals

Each electric utility whose rates are regulated by the Commission shall issue a request for proposal (RFP) to provide any new supply-side capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state, as well as customers located in other states but served by the utility, during the initial three-year planning period to be considered in each IRP to be filed, as outlined in MCL 460.6t.

The utility shall comply with the following:

a) The utility shall include documentation demonstrating that the RFP process was completed with the IRP application;
b) The utility's RFP process is subject to audit by the Staff;
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the Commission's code of conduct, and applicable state, federal,

[2] Utility Clean Energy Plans should follow the guidance outlined in the Clean Energy Plan Filing Requirements.

and Commission rules, and any adherence with the competitive procurement guidance in Case No. U-20852;

d) The RFP shall allow for proposals of sizes smaller than the total capacity need such that a combination of projects is needed, including but not limited to distribution connected resources, to provide new supply-side capacity, pursuant to MCL 460.6t(6); and
e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a Power Purchase Agreement for a period that is the lesser of the study period or the useful life of the resource type proposed.

Engagement and Public Outreach Process

Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision- making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; (5) reduce utility regulatory risk by building understanding and support for utility resource decisions; and (6) ensure the inclusion of diverse voices, including environmental justice communities and Tribal Nations. The utility should incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing. Clean Energy Plan (CEP) participant engagement may be combined with the IRP participant engagement to the extent practical.

In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have an opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing and the utility is encouraged to share these documents with the public. Documentation should include:

a) Workshop dates and times, including times outside of the workday;
b) Evidence that a notice of the workshops was provided to the public;
c) Meeting minutes;
d) Meeting or workshop attendance lists;

e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application;
f) Description of how the public outreach process influenced the IRP; and
g) Description of community outreach efforts for environmental justice communities and tribal lands within the Company's service territory. Environmental justice communities should be identified using the MI EJScreen Tool.

A minimum of two engagement workshops is recommended. An engagement workshop will give interested persons an opportunity to provide input regarding the utility's assumptions, inputs, and modeling methodologies employed during the development of the IRP. The utility is encouraged to provide basic information regarding the IRP filing process and how interested persons could participate. The utility is encouraged to invite interested persons, including expected intervenors, and the Staff, to its engagement workshops. The utility shall invite all Tribal Nations with tribal lands in their service territory and provide a point of contact with a local utility engagement specialist that can address how the IRP and CEP may impact tribal lands.

If the engagement workshops are not open to the public, two additional hybrid public meetings with the option for both virtual and in-person attendance are recommended. If 5% or greater of a utility's residential customers are in communities identified as part of the Environmental Justice (EJ) analysis, it is recommended that at least one of the two additional hybrid public meetings are located in any of the identified communities. The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment. The utility is encouraged to provide basic information regarding the IRP filing process and how interested persons and members of the public could participate. The public meetings should be offered in the utility's service territory in geographic locations that are convenient for customers, prioritizing accessibility and convenience for customers identified in the EJ analysis. Advanced notice should be provided to customers in the utility's service territory. This should include Tribal governments, local governments, and community-based organizations. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

The public meetings should be conducted in a manner accessible to those with disabilities, including those that are hearing and visually impaired. The public meetings should also be

available to those whose first language is not English upon request and to the extent practicable.

If the utility chooses to hold pre-filing workshops, including engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any pre-filing workshops, and shall file the report with the IRP application.

All presentations, recordings, comments, and transcripts from those presentations open to the public should be maintained on a website in a location open to the public for the duration of the outreach process and the duration of the IRP case, until a final commission order is published.

Risk Assessment Methodology

The utility's IRP filing shall include a thorough risk assessment of the proposed resource plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), all additional utility-developed scenarios and utility-developed sensitivities related to early retirement that are filed with the IRP application. The utility-submitted alternative build plans should be feasible and differ in generation mix from the proposed resource plan and MIRPP plans.

The intent of the risk assessment is to test the optimized resource strategies for each scenario and the proposed course of action (PCA) to determine how each strategy would perform in an unexpected range of possible futures. The utility shall provide detail on how the risk assessment was conducted, including the impact of atypical weather conditions that occur at least as frequently as once in ten years.[3,4,5] The utility shall also include all extreme weather events of the last 20 years, identified by State declaration of an emergency. Additionally, the utility should detail any scenario and sensitivity runs conducted with the utility's risk assessment where the PCA or proposed alternative build plan results in unserved load. Utilities are encouraged to link variables that can be shown to have correlations or dependencies with each other. Examples of variables to be considered under weather conditions include but are not

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[3] Summary Climate Information, https://glisa.umich.edu/summary-climate-information/
[4] Tools for Tracking Climate Change, https://ccr.nelson.wisc.edu/
[5] Atypical weather conditions are weather events that meet the definition of "catastrophic conditions" from the MPSC Service Quality and Reliability Standards less the periods with a State declaration of emergency

limited to changes in load, operations, and resource availability.

The IRP shall include a discussion of the methodology used for risk assessment, including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk assessment include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent- based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Utilities with one million customers or more, shall include a Local Reliability Requirement (LRR) analysis of the proposed resource plan in the IRP filing. The LRR analysis shall estimate a five-year outlook of the LRR in the local resource zone. The analysis shall be conducted consistently with the resource adequacy construct used by the regional transmission organization (RTO) or independent system operator (ISO). The purpose of this calculation is to estimate the marginal impact of the utility's proposed resource plan on the resource adequacy of the local resource zone during the first five years of the plan.

Confidential Information

Transparency and the use of data that can be shared with the Commission, the Staff, and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials and claims that information is proprietary or confidential should be justified by the utility.

Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution

system.

Non-Wires Alternatives - An electric grid investment or project that uses distribution solutions such as DER, energy waste reduction (EWR), demand response (DR), and grid hardware and software, to defer or replace the need for distribution system upgrades.

Environmental Justice Communities – Overburdened, vulnerable, underserved, or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen). If MiEJScreen tool is not available, the utility should work with and take feedback from Staff, EGLE, and interested parties when determining which other tool or methodology to use.

Environmental Justice Analysis – The identification of and assessment of impacts to Environmental Justice Communities, as well as the identification of communities with a minimum percentile of 75 in either the Low Income Population or Black, Indigenous, People of Color population layers in the MiEJScreen tool.

Demand-Side Resources - Resources serving resource adequacy needs by reducing or shifting load, which reduces the need for additional generation, including but not limited to EWR, DR, grid and software controls, behind-the-meter distribution connected storage, etc.

Co-Benefits – Benefits that are quantified as part of another planning process that are important for the justification of a resource included in the IRP. Examples include a cost reduction to the distribution system or transmission system that has been evaluated in the distribution planning or transmission planning process.

Approval of Costs

For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side resources, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6t(11) through (12), the following information, data, and documents

shall be provided:

For specific supply-side resources (inclusive of storage technologies and clean emerging technologies), that are planned to commence within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be provided:

a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following:
    1. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
    2. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
    3. Annual depreciation on the capital investment.
b) Projected annual return and income taxes on capital investment;
c) The operation and maintenance (O&M) costs over the life of the facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt (kW);
d) Projected property taxes;
e) The rates of escalation of cost, including:
    1. Capital costs;
    2. O&M costs which are variable and related to fuel;
    3. O&M costs which are variable and unrelated to fuel; and
    4. O&M costs which are fixed.
f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility;
g) Equivalent availability factors, including both scheduled and forced outage rates;
h) Capacity factors for each year in the planning period;
i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and cycling conditions for each year in the planning period;
j) Heat rates (efficiency) for various levels of operation;

k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences;
l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre-commercial operation date testing;
m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility;
n) Procurement strategy, including third-party and company owned contracts, and any adherence to the most recent Commission approved Competitive Procurement Guidance that includes a description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6t(8)(c);
o) A summary description of the expected decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new resources; and
p) A detailed description of any implementation risks that are specific to each generation technology type.

Renewable Resources: The utility shall file data consistent with any approved renewable energy plan. Revenue requirement and incremental costs shall be calculated to include the following:

a) Capital, O&M costs for renewable energy systems (including property taxes and insurance for renewable energy systems);
b) Financing costs;
c) Costs that are not otherwise recoverable in base rates, including interconnection and substation costs;
d) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance;
e) Cost of Contracts;
f) Expenses incurred as a result of governmental action including changes in tax or other laws;
g) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029;

h) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029);
i) Provide the following information in relation to renewable resource cost recovery:
    1. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
    2. Forecast through the end of the renewable plan period of the regulatory liability balance.
j) Procurement strategy, including third-party and company owned contracts. Address whether the procurement strategy adhered to the most recent Commission-approved Competitive Procurement Guidance that includes a description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6t(8)(c); and;
k) A summary description of the expected decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new renewable resources.

Energy Storage: The utility shall provide any relevant data, according to its plan to procure its share of the statewide energy storage target, established under MCL 460.1101(1). The following information shall be provided in relation to the energy storage procurement plan:

a) If the utility has not yet filed for approval to procure its proportional share of the statewide energy storage target, the utility must seek approval of these storage resources in an IRP filed no later than December 31, 2029;
b) Capital and O&M costs for energy storage systems;
c) Financing costs;
    1. Procurement strategy, including third-party contracts, build transfer, or company owned. Address how the utility will adhere to the most recent Commission approved Competitive Procurement Guidance;
    2. A description of how the procurement process will commit to meeting the labor standards set out in PA 231 Section 6t(8)(c);
    3. A summary description of the expected decommissioning process, anticipated costs, and how the utility intends to provide safety and assurance of proper

disposal, with consideration of material salvage and recycling, for proposed new energy storage resources.

EWR: The utility shall provide the following information in relation to EWR programs cost approval and recovery (including utility providers that elect the State Administrator under the alternative compliance program, also known as the Efficiency United or EU program). For each individual program or group of programs, provide:

a) Total annual cost, energy, and capacity including:
    1. Annual O&M cost for each individual portfolio of EWR programs;
    2. Annual capital cost for each individual portfolio of EWR;
    3. Expected cost-sharing or financial incentive granted to the utility by the Commission; and
    4. How the utility included the avoided distribution costs when evaluating the most cost effective EWR amount in all IRP scenarios.
b) Calculated generation savings using annual marginal line loss rates for energy and marginal line loss rates at peak hours for capacity to determine total peak demand (MW) and energy (megawatt-hours (MWh)) reduction potential;
c) Total resource capacity (MW) and whether or not it is reported/registered to the applicable regional transmission organization (RTO) or independent system operator (ISO). If the resource is registered to an applicable RTO/ISO, then detail the resource type it is registered as.

DR, DER Programs, and other demand-side resources: The utility shall provide the following information in relation to DR programs, DER programs, and other demand-side resources cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:
    1. Annual O&M cost for each individual program of DR, DER, and demand-side programs;
    2. Annual capital cost for each individual program of DR, DER, and demand-side programs; and
    3. Expected cost-sharing or financial incentive granted to the utility by the Commission.
b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable;

1. Maximum single event demand reduction;
2. Total resource capacity (MW) and whether or not it is reported/registered to an applicable RTO or ISO, then detail the resource type it is registered as;

c) Total energy reduction achieved (MWh); and
d) Description of program, including customer enrollment, technology used, and marketing plan.

Waivers and Process for Smaller and Multistate Utilities

An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming 10 years.

If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application. An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP.

A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard.

Northern States Power Company-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in MCL 460.6t(4) regarding multistate IRPs, Northern States Power Company-Wisconsin and Indiana Michigan Power Company may utilize the IRP filing requirements of another state in accordance with those provisions. However, the Commission reserves the right to request

additional information to facilitate its review of the IRP as it relates to Michigan.

IRP Filing, Data, and Documentation

The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:

a) Letter of transmittal expressing commitment to the approved resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisition strategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances;
b) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy;
c) The data and information requested in the Commission's IRP Filing Requirements included herein;
d) Any information that the Commission in its orders regarding the utility's previous IRPs or other dockets required to be provided in this present IRP. This information should also be provided to interested persons at public outreach meetings; and
e) Any other information deemed relevant by the utility.

The utility's IRP filing shall include an IRP document(s) and application information, including testimony and exhibits, that describes and documents the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with this provided outline and include at least the following items:

I. Executive Summary: An IRP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall be an informative non-technical description of the resource plan proposed by the utility and resource acquisition strategy. The executive summary shall summarize the contents of the IRP document and shall include the following:

a) An overview of the planning period examined in the IRP analysis and application;
b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy;

c) A summary of the state, federal, ISO, RTO resource adequacy regulations applicable to the utility;
d) A summary of the analytical approach used in the utility's analysis and the types of new resources considered;
e) A description of how the analytical approach considered potential resource co-benefits from other planning processes, such as distribution or transmission planning;
f) A summary of any retirement analysis performed;
g) A description of how the environmental justice (EJ) analysis results influenced the utility's proposed course of action (PCA);
h) The Company shall include a graph that depicts a stacked bar graph that includes the RTO/ISO capacity credit[6] of all existing resources and PCA resource additions, color designated by resource type, that it will use to serve demand in each year for all planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin;
i) The Company shall include a graph that depicts a stacked bar graph that includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period;
j) The Company shall include a graph(s) that summarizes the total of each of the following pollutants projected using the PCA in the MIRPP Scenario 1 for each year of the planning horizon. A graph should be included for nitrogen oxide (NO_x), sulfur dioxide (SO_2), particulate matter (PM), mercury (Hg), volatile organic compounds (VOC), carbon dioxide (CO_2). The graph should also depict the utility's progress toward or achievement of State, Federal and utility announced goals or requirements by including annotations for those goals on the years they apply;
k) The Company shall include a discussion of the estimated costs of the PCA; and
l) Any other information that would aid the public understanding of the utility's proposed resource plan.

[6] For example, MISO Zonal Resource Credit.

II. Table of Filing Requirements:

The utility shall provide a table that clearly identifies where in the filing it has met all the filing requirements. It shall include locations in testimony, exhibits, and workpapers.

III. Testimony Introduction: The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:

a) General description of the utility's existing energy system, including:
    1. Net present value revenue requirements (NPVRR),[7] with and without any financial performance incentives for demand-side resources;
    2. Summary of existing generation and PPAs by fuel type;
    3. Utility's existing capacity resource mix;
    4. Utility's service territory and breakdown of customer class composition; and
    5. Description of planning period analyzed;
b) Statement of power need;
c) Identify and explain the basis for the forecasted price of energy, capacity, fuels, and of peak demand and energy requirements, over the study period used in each scenario and sensitivity evaluated by the utility as part of the IRP process;
d) Market and regulatory environment influencing resource planning decisions:
    1. RTO market and state regulation structure if a multistate utility;
    2. Potential changes to RTO capacity market;
    3. Electric customer choice;
    4. Transmission expansion;
    5. Environmental;
    6. Renewable portfolio standards; and
    7. Other;

[7] The assumed discount rate shall be included along with a justification for the assumed discount rate. Results should be presented in nominal dollars.

e) IRP planning process; and
f) Engagement report.

IV. Analytical Approach:

a) Describe the modeling process, including the duration of the study;
b) The utility shall describe and identify how its model approach optimizes resources to meet load and demand for all times of the year and for each year of the planning horizons. The utility shall explain how the model considers the seasonal and operational characteristics of all resource types, including generation profiles, forced outages, facility derates, seasonal or limited availability of resources, etc.;
c) The PCA and Utility Alternative (if applicable) should be evaluated under all scenarios and sensitivities listed in the MIRPP;
d) If the utility presents a retirement study as justification for an early resource retirement or to delay the scheduled retirement of a fossil fuel plant, the utility should refer to the minimum scenario and sensitivities in Appendix G of the MIRPP when conducting that analysis. The previously approved retirement dates should also be evaluated under the scenarios and sensitivities indicated in Appendix G. To allow for evaluation over the same time horizons, the portion of the previously approved IRP that does not have resources, should include any new (additional) generic resources as selected by model optimization.
e) If the utility is proposing the retirement of a baseload or intermediate coal or natural gas power plant with a date that differs from the most recently approved IRP:
    1. The utility shall share the dates being studied, as well as the criteria that will be analyzed as part of the IRP, with Staff. This information will be provided in the utility's initial IRP filing.
    2. To test the optimized resource strategies for the proposed retirement, the utility shall model sensitivities to ensure the retirement dates were stress-tested and the PCA is reasonable and prudent under various conditions.
    3. Sensitivities may include, but are not limited to, high load growth, high natural gas prices, and extreme weather conditions.
    4. The utility must present the retirement analysis methodology, summarize the results, and demonstrate that the PCA is reasonable and prudent under the conditions tested.

The utility must also demonstrate that the PCA complies with the renewable energy plan requirements of MCL 460.1028, the clean energy requirements of MCL 460.1051, the energy waste reduction measure in MCL 460.1077, and the energy storage target of MCL 460.1101, unless the retirement analysis is part of a request for extension of compliance with the clean energy plan under MCL 460.1051(b).

5. If the retirement proposed as part of the PCA is not supported under one or more of the conditions or sensitivities assessed, the utility shall include in testimony how the company plans to monitor the risk in advance of retirement as well as a risk mitigation plan.

f) If the utility is proposing the retirement of a baseload or intermediate coal or natural gas power plant with a date that differs from the most recently approved IRP:

g) Describe and provide a justification for the risk assessment approach adopted from the Risk Assessment Methodology section:

1. The utility shall describe and document its quantification of the risk that affects the evaluation of the various resource plan options;
2. The utility shall provide a tabulation of the key quantitative results of that assessment, and a discussion of how those findings affected its decision on a resource plan; and
3. If multiple forms of risk assessment are presented the utility shall explain why certain risk variables could not be included in or are unsuited for one type of risk assessment or another. Considering a risk variable under multiple forms of risk assessment is not discouraged.
4. The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various resource plan options were judged; describe how these risk variables were judged to be appropriate and explain how these were determined; and describe the modeling tools and data sources employed during the capacity expansion, and other modeling processes; and
5. Interactions between risk variables should be captured to the extent that it is practical. Evaluation of variables in isolation is acceptable so long as there exists a comprehensive evaluation of resource plans risks that captures interactions and shows overall risk of appropriate build plans. A comprehensive risk assessment should at

least include optimized build plans from the required MIRPP scenarios, the proposed resource plan, and any alternative resource plans presented by the utility.

h) If the utility includes any new large loads in its PCA (loads that are greater than 300MW with a load factor of greater than 80%) then provide the following information without the inclusion of those large loads:
   1. Total system cost;
   2. Net present value revenue requirement and;
   3. Rate impact of utility's base case scenario.

V. Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities; and
b) In addition to the utility's own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP, approved by the Commission in Case No. U-21867, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.
c) The utility should show how it used the MIRPP-approved Scenarios, or any additional scenarios that the utility decides to include, to develop the PCA and any alternative build plan and to justify any retirement decisions. To the extent that some portion of the MIRPP-approved scenarios is of concern for the utility, the utility can request a waiver, in advance of the filing of the IRP, to deviate from certain aspects of a scenario or sensitivity. Examples may be to request using a different gas price or updated EWR information.
d) Consistent with MCL 460.1051(b), if a utility has requested and been approved for an off-ramp for their REP, the IRP should align and reflect the Commission's approval. If the utility is using the results of its IRP to support a request for an off-ramp, the utility should run Scenario#1 and Scenario#2 with an additional sensitivity (sensitivities) that illustrates the resulting difference in cost and overall build plan as compared to meeting the standard without the use of an off ramp.
e) The utility should model its PCA, any utility proposed alternative, any additional scenarios the utility decides to include, and previously approved IRP build plan in all scenarios and sensitivities presented in the MIRPP.

VI. Existing Supply-Side Resources: Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

a) Overview;
b) Fossil-fueled generating units;
c) Nuclear generating units;
d) Hydroelectric generating units;
e) Renewable generating units;
f) Energy storage facilities;
g) Third-party contracts: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource; and
h) RTO/ISO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.).

VII. Demand-Side Resources: Historical and projected load management and DR programs for the utility in terms of MW and RTO or ISO Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and DR events for each program. The following items are to be included:
    1. Description of current DR and load management programs for the IRP study horizon, including the amount of load reductions and the expected hours of interruption per day, month, and year for each program;
    2. Review the historic performance of existing demand-side programs in delivering benefits and how the utility used such information in its DR resource decisions;
    3. Describe the utility's method for identifying and deciding whether to pursue cost-effective and achievable DR, and determining whether to purchase energy rather than relying on DR; and
    4. A description of any other programs the utility is considering that could potentially expand DR resources, including expected load reductions and operating parameters.

VIII. Renewables and Renewable Portfolio Standards Requirements: Projected energy purchased

or produced by the utility from renewable energy resources.

a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers;
b) Specify whether the number of MWh of electricity used in the calculation of the REC portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state;
c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period;
d) A description of how the electric provider's plan is consistent with the renewable energy requirements established by the Michigan Legislature (e.g. 50% renewable energy by 2030 and 60 % by 2035;
e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customer- initiated renewable energy;
f) Describe how the electric provider will meet the demand for customer- initiated renewable energy, and;
g) Describe how the electric provider has included distributed generation (DG) as a selectable resource within its modeling for both the IRP and CEP, including interconnection to utility distribution as well as behind-the-meter. The utility is required to consider and model aggregated DG, distributed energy resources (DER) and virtual power plants (VPP) as selectable resources in its IRP. The utility should delineate the costs are paid by DG customers to participate in the program and the costs are paid by all rate payers. Only costs to all rate payer should be included when modeling DG resources. Costs paid by the DG customers (program participants) should not be included in the model but should be considered as compared to the applicable bill credit and DG customer savings to analyze expected participation.[8]

[8] This analysis should not solely identify solar generation existing within the utility's system, but instead utilize the most up-to-date information about trends and costs to predict uptake and create a forecast of future DER resources. Information about the assumptions that the utility used to create its DER forecast should be included in the filing.

IX. Energy Storage Target: Description of how the utility will meet its proportional share of the statewide energy storage target required by MCL 460.1101(1).

a) If the utility has not yet filed for approval to procure its proportional share of the statewide energy storage target, the utility must seek approval of these storage resource in an IRP filed no later than December 31, 2029;
b) Identification of the utilities proportional share of the statewide energy storage target of 2500 MW, to be calculated using the methodology approved by the Commission in Case No. U-21751;
c) Describe the Company's storage procurement plan to meet its required share of the statewide target, including providing the following data on an annual basis:
    1. Nameplate capacity and energy output of new resource additions;
    2. Storage technology/chemistry deployed and in what amounts;
    3. Mix of energy storage capacity that is long-duration and multi-day in duration;
    4. Project costs;
    5. If the utility's energy storage plan differs from the resultant capacity expansion results, the utility should present its analysis on how it determined the optimal mix and timing of different energy storage technologies and duration capabilities to meet its share of the statewide target, including any modeling or description of other analytical approaches taken.

X. Clean and Renewable Energy Standards Section: Detailed resource plan that clearly illustrates how the utility has aligned its IRP with its CEP and how the utility will meet the Clean Energy Standards of 80% clean energy by 2035 and 100% clean energy by 2040. The utility must:

a) Describe the utility's planned REC portfolio;
b) Forecast RECs obtained via Michigan incentive RECs;
c) Forecast expected compliance levels by year to meet the renewable portfolio targets;
d) Identify key assumptions used in developing these forecasts and the proposed resource portfolio; and
e) Identify risks which may drive performance to vary.
f) If the utility is requesting an extension of a renewable energy credit portfolio deadline pursuant to MCL 460.1032, the utility must provide justification for the extension.

g) Model at least one portfolio without an extension (i.e. what it would look like given the renewable energy deadline without the extension).

XI. Peak Demand and Energy Forecasts: A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of EWR expected to be achieved annually, and the cost of the plan:

a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve.

b) Subsections:

1. Key variables used to develop forecast;
2. Long-term forecasting methodology;
3. Forecasting uncertainty and risks;
4. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers);
5. Base load forecasts should include assumed losses and demand forecast;
6. Base load forecasts should include any contracted large loads and include a description of the load and peak demand characteristics of any large load included in the utility's base or alternative load forecasts.
7. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. U-21219, or subsequent Commission orders relating to IRP modeling parameters and requirements;
8. Describe in detail how the forecasts used for IRP modeling align with forecasts used for distribution planning;
9. Detail information about how the Company considered DER and non-wired alternative solutions for the potential to offset future utility-scale resources;
10. Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts;
11. Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts; and
12. Detail exactly how much EWR is embedded in the utility's load forecasts.

13. Detail the addition of projected large load that are not included in the base load forecast but will be used for Scenario #1 large load sensitivity that includes a description of the total incremental large load in the Company's queue to develop a low, medium and high large load forecast. The low, medium, and high forecasts should be derived using a designation of probability for each project in the customer queue. Please detail any additional methodology about how the utility has determined its low, medium and high large load forecast and how this aligns with publicly disclosed load information.

XII. Capacity and Reliability Requirements: The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, and RTO capacity and reliability regulations, laws, rules, and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including, where feasible, the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall identify any relevant changes to the applicable state, federal, or local laws, rules, and regulations. The utility shall also identify any major ISO or RTO capacity and reliability requirements that have occurred since its last IRP filing, including narrative that identifies how its PCA satisfies those requirements. The utility shall include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.

XIII. Transmission Analysis: In accordance with MCL 460.6t(5)(h), the utility shall work with their local transmission owner to include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:

a) The utility shall work with their local transmission owner to assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options. The analysis shall include a discussion of how implementation of grid enhancing technologies (GETS) can facilitate, defer, or replace other transmission and resource investments and/or reduce market congestion costs;
b) In collaboration with the local transmission owner, include an analysis of any co-benefits of storage, specifically the transmission system benefits associated with transmission interconnected storage that is not designated as "storage as transmission only asset;"

c) A detailed description of the utility's efforts to engage local transmission owners throughout the utility's IRP process. In an effort to inform the IRP process and assumptions, a meeting schedule in coordination with the transmission owner should be determined that supports engagement through the process. The filing should include a summary including meeting dates, number of meetings and how the engagement influenced the utility's decisions;
d) Detailed meeting minutes for utility/transmission owner meetings should include any requested studies, discussions about assumptions and any conclusions made during the meeting, alternatives that were reviewed, any other pertinent information that can be made public or provided through typical contested case confidentiality agreements;
e) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;
f) To the extent available, any information provided by their local transmission and RTO owner indicating the anticipated effects of fleet changes proposed in the transmission system, including both generation retirements and new generation, subject to confidentiality provisions; Any information provided by their local transmission owner, including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing a local resource zone's (LRZ) import or export capability; (2) facilitating PPAs or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources; (5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits;
g) In collaboration with their local transmission owner, to the extent available**,** any information regarding (1) identification of system locations or regions where energy resources can interconnect to the transmission system with minimal transmission investment, (2) recent studies, to the extent that they are available, that indicate ways in which the capacity import or export capabilities can be increased or may change and the resulting impacts to the local clearing requirement;

h) Any transmission studies performed by their local transmission owner that support the resource plan proposed by the utility;
i) In conjunction with the local transmission owner, provide an analysis of transmission costs for access to out-of-state resources conducted by either the RTO, transmission owner(s), and/or utility in a format that can be made available to public; and
j) Provide RTO reports or web links to report locations that contain information relied upon to support transmission related model assumptions in a format that is conducive to public availability.

XIV. Fuel: The utility shall include the following:

a) Overview;
b) Natural gas price forecasts under the various scenarios;
c) Oil price forecasts under the various scenarios;
d) Coal price forecasts under the various scenarios;
e) Delivered natural gas prices to existing and new utility-owned generating plants;
f) Delivered oil prices to existing and new utility-owned generating plants;
g) Delivered coal prices to existing and new utility-owned generating plants;
h) Projected annual fuel costs under the various scenarios;
i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility; and
j) Any other fuels used for electric generation by the utility.
k) New generation or retrofitted generation costs to connect to fuel and store CO2 where applicable.

XV. Resource Screen: Describe the utility's options of resources, including combinations of resources constructed as a single facility (such as storage combined with a generation source), to serve future electric load such as utilizing existing and planned resources (including future load from the electric provider's voluntary green pricing program and any special contracts), build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a PPA. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs and performance data of each modeled resource option and combination

of resource options shall be provided with the utility's filing:

a) Existing and approved resources;
b) New build:
    1. New generation technology and operating assumptions;
    2. New generation development costs;
    3. New storage technology and operating assumptions;
    4. New energy storage development costs; and
    5. Development costs and operating assumptions for combinations of resources constructed as a single facility;
c) DERs inclusive of non-wires alternatives (NWA) identified in other planning processes;
d) Demand-side Resources inclusive of NWAs identified in other planning processes;
e) Market capacity purchases:
    1. Regional market supply outlook;
    2. Availability of market capacity; and
    3. Market capacity price assumptions;
f) Long-term PPAs; and
g) Transmission resources:
    1. Overview;
    2. Existing import and export capability;
    3. Transmission network upgrade assumptions for the IRP; and
    4. Import and export impact on resource strategy.

XVI. Modeling Results: An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included. They are not exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification, minimization of impacts to communities identified in the EJ analysis, etc., or a particular combination);
b) Results for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that include annual incremental revenue

requirements, incremental present value of annual revenue requirements and net present value of revenue requirements, and portfolio capacity, including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors;

1. Base case portfolio options to be selected from;
2. Analysis of IRP results;

c) Risk assessment is presented with graphics and data that illustrate the results of any stochastic risk analysis performed such that the probability distributions are clearly defined along with relative positions of the distributions so that plans can be directly compared on a single graph. The use of a box and whisker plot and/or efficient frontier plot is recommended; and

d) Impacts on resource adequacy for the resource zone.

XVII. Proposed Resource Plan: Include a detailed description of:

a) The type of generation technology proposed for a generation facility or combination of resources constructed as a single facility contained in the plan and the proposed capacity of the generation facility or combination of resources constructed as a single facility, including projected fuel costs under various reasonable scenarios;

b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and PPAs;

c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and

d) How the utility will meet local, state, and federal laws, rules, and regulations under the PCA;

e) Include a detailed description of the impact of the CEP on the diversity of the utility resource portfolio. Include qualitative and quantitative details that include consideration of the benefit associated with resources that add to generation diversity and provide a monetarily quantifiable benefit that would not be achievable absent the resource in a narrative;

f) How the utility's IRP and CEP align with or differ from the Company's most recently filed Renewable Energy Plan (REP). If the IRP and CEP diverge from the REP, describe how they will meet the Renewable Energy Portfolio Standard set out in PA 235 and how these differences will influence future REP filings;
g) How the utility's IRP storage builds meet the utility's share of the Energy Storage Target as set out in PA 235; and
h) How the utility's IRP aligns with or differs from the utility's most recent EWR plan and how the EWR in the PCA complies with PA 295 as amended.

XVIII. The utility shall describe the process used to select the proposed resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its proposed resource plan satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified;
b) Utilize renewable and demand-side resources to comply with existing laws, goals and, in the judgment of the utility, are consistent with the public interest to achieve state energy policies;
c) In the judgment of the utility, the proposed resource plan, in conjunction with the deployment of DR measures, has sufficient resources to serve load forecasted for the implementation period;
    1. A NPVRR comparison of its proposal and reasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the NPVRR of the utility's proposed resource plan and any alternative resource plans, including the alternative resource plans resulting from the Commission-approved modeling scenarios.
    2. A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning (such as reliability and resiliency benefits), when those benefits are unable to be captured through capacity expansion modeling runs, to the extent that the co-benefits were relied upon for justification of resource decisions;

d) Include a detailed analysis for any resource type that the utility utilized an analysis outside of the integrated resource model to determine net-cost, external benefits, and additional value streams:
    1. Detail the net-cost method used when modeling any resource, where presumed benefits are netted against the costs of a resource to account for benefits outside of the model. A complete account of costs and assumed benefits should be provided such that the metrics and value given to achieving those metrics is clear and transparent;
    2. Detail benefits and value streams that are outside of the model that are included in the utility justification for a resource. A detailed analysis should be transparent and included in the utility filing; and
    3. Detail how the utility considered whether benefits applied to one resource type are or are not also attributable to other resources.

XIX. The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule to report the status of an approved plan in accordance with MCL 460.6t(14);
b) A schedule and description of actions to implement ongoing and planned demand-side programs and demand-side rates;
c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction;
d) A description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state;
e) A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state; and
f) A description of how the utility plans meet the labor standards set out in PA 231 Section 6t(8)(c) for the construction of new generation capacity and rehabilitation of existing capacity resources.

XX. Rate Impact, Financial Information, and Affordability: PCA only rate and affordability

impact.

a) The average rate impact by customer class (i.e., residential, C&I, etc.). The analysis shall include the Utility's most recently approved base rate revenue requirement for full-service customers, a forecast of the revenue requirement growth based on a projected inflation factor, the percentage of the production cost allocations assignable to each customer class, based on the prior approved rate case, and the estimated delta revenue requirement of the PCA to determine the average rate impact.
    1. The Utility shall identify the class allocation of the incremental revenue requirement, the class sales forecast and compare it to the current average rate, and class allocation of the incremental revenue requirement shown as a percentage.
    2. This rate impact analysis should also include the impact to customers as a result of PCA resources that are cost recovered using the PA 235, Section 22 revenue recovery mechanism.
b) The utility shall show the affordability impact of the PCA as compared to its previously approved build plan. The utility shall describe its methodology and data sources including but not limited to income-based segmentation, publicly available data used, any limitations of data availability, proxies such as demographics or housing data, etc. Example methodology is in Appendix 2. If any identified income range is expected to increase an energy burden at or above 6%, the utility shall provide a discussion of available assistance, EWR programs and measures, or other options that could aid in mitigating the expected increased energy burden for the areas identified.[9]

XXI. The utility shall describe the financial assumptions and models used in the plan. The resource plan shall include, at a minimum, the following financial information, together with

[9] This affordability analysis is based on publicly available data as of the time of filing. It relies on generalized assumptions and broad-based inputs to evaluate the affordability implications of the PCA in this IRP. The results are intended to inform the Commission's evaluation of long-term electric supply planning decisions in this IRP. This analysis serves as one step in advancing affordability considerations in resource planning and considers the impacts of resource investment only.

supporting documentation and justification:

a) The general rate of inflation;
b) The allowance for funds used during construction rates used in the plan;
c) The cost of capital rates used in the plan (debt, equity, and weighted) and the assumed capital structure;
d) The discount rates used in the calculations to determine present worth;
e) The tax rates used in the plan;
f) NPVRR for the plan;
g) Nominal incremental revenue requirements by year; and
h) Average system rates per kWh by year.

XXII. Environmental Considerations and Emissions Analysis: Describe how the utility's resource plan and any alternative resource plans presented in the application will comply with all applicable local, state, and federal environmental regulations, laws, and rules.

a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources;
b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP;
c) Include a chart that compares the total projected carbon emissions under each scenario analyzed (no sensitivities applied), including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify its use of a carbon accounting methodology, identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases or other Commission approved methodology;[10]
d) If the Company is proposing retirement of an existing resource due to an environmental regulation, clearly identify the future capital cost for environmental regulations and other capital investments in the facility. If costs are identified as avoided capital costs, provide

[10] Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases, https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019.

sufficient detail to support the capital cost as avoidable, meaning dollars will never be spent, or capital cost will simply be transferred to another cost category. For example, becoming cost of removal, or fully avoidable capital costs;

e) Hold a technical conference with MPSC and Department of Environment, Great Lakes, and Energy (EGLE) staff within 30 days after the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers; and

f) Identify, quantify, and provide evidence in the filing that shows progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario (no sensitivities applied), the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period.[11][12]

XXIII. EGLE Advisory Opinion and Environmental Justice Analysis: Ensure the advisory opinion of EGLE in utility IRP cases is supported by a comprehensive health and environmental impact analysis in support of the State's environmental justice goals and Governor Whitmer's September 2020 Executive Directive 2020-10 and the Public Act 231 Section 6t.

a) Scope of portfolio build plans (herein referred to collectively as portfolios) evaluated as follows:
    1. Portfolio 1: Previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period);
    2. Portfolio 2: Utility PCA portfolio run in MIRPP Scenario 1;

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[11] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) regarding the urgent threat to the environment, economy, and the health and well-being of Michigan's residents posed by climate change and its implications. ED 2020-10 committed Michigan to pursuing a reduction of at least 26 to 28 percent in Greenhouse Gas (GHG) emissions below 2005 levels by 2025 and economy-wide carbon neutrality to be achieved no later than 2050 and maintained thereafter.

[12] April 22, 2021, President Joe Biden announced carbon reduction targets for the United States building upon carbon reductions to date. The new targets call for an economy-wide net GHG reduction of 50 to 52 percent from 2005 levels by 2030 and net zero GHG emissions economy-wide by no later than 2050.

3. Portfolio 3: Optimized portfolio in MIRPP Scenario 1;
4. Portfolio 4: Optimized portfolio in MIRPP Scenario 1 with high load sensitivity; and
5. Portfolio 5: If applicable a utility's reasonable alternative(s) to the PCA presented by the utility in MIRPP Scenario 1.

b) The utility will provide the following facility/unit level data and total annual fleet data, in an Excel spreadsheet(s) expressed in total tons, to EGLE for the following pollutants:
   1. Nitrogen oxides (NO_x)
   2. Carbon monoxide (CO)
   3. Particulate matter (PM)
   4. Lead (Pb)
   5. Mercury (Hg)
   6. Volatile organic compounds (VOC)
   7. Carbon dioxide (CO_2)
   8. Sulfur dioxide (SO_2)

c) For each portfolio, identify existing facilities and potential future facilities with known locations, including peaking units, that are within 3 miles of communities specified for the Environmental Justice Analysis. Analyze all portfolios to quantitatively assess the projected emissions of identified facilities for each respective portfolio, and the differences in each portfolio's projected emissions for that unit relative to portfolio #2. Emissions should be reported in the appropriate unit of measure. If a utility does not have generation within a 3-mile radius of a community identified by the Environmental Justice Analysis, then an assessment is not required.

d) Using the facilities identified in (c), above, quantitatively assess changes to air emissions from early retirement and/or conversion of fossil fuel-fired facilities to the extent the plan includes either conversion or retirement.

e) Using the facilities identified in (c) above, qualitatively assess the potential impacts of all portfolios including utility proposed early retirements, retained, or converted fossil fuel-fired facilities. The assessment should address water quality, waste disposal, and expected changes in land use for new or retiring resources to the extent known at the time

of filing. The assessment should evaluate whether the utility's proposed PCA reduces harm to the health and safety of individuals in Environmental Justice Analysis communities in comparison to the alternatives considered;

f) To determine health impact estimates for air emissions, the utility will use the environmental Benefits Mapping and Analysis Program–Community Edition (BenMAP-CE), or the Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool. Based on the pollutant parameters compatible with the chosen tool, this air emissions data analysis will be performed to provide health impact estimates. This includes:
    1. Assessment of annual fleetwide health impacts or benefits of any of the following: early retirement of fossil fuel-fired units, conversions to a different fuel source(s), and newly constructed/acquired generation units (to the extent the location is known and including renewable energy adoption, new fossil fuel-powered generation, nuclear, etc.).[13] Using emission projections from section XXIII subsection b), compare results for all portfolios with a focus on a comparison of portfolio #2 and #5 (if applicable) to portfolio #1; and
    2. County-level results (or finer) for any county that contains retired, new (if location is known), or converted fossil fuel-fired units in or within 3 miles of communities specified for the Environmental Justice Analysis.

g) Assess PM2.5 and NOx emissions from each individual electric generating unit in portfolio #2 located within 6 miles of communities specified for the Environmental Justice Analysis. If existing unit emissions for either pollutant increase above the historic variability of the unit, conduct emissions impact analyses for those units. The current emissions should be used to establish a baseline by which to compare the future impacts of portfolio #2 units. Any analysis conducted pursuant to this item should include other emissions impacts on the area, as appropriate. The goal of this analysis is to assess how the PM2.5 and NOx emissions may change in communities specified for the

[13] If the online version of an analytical tool does not have the data needed for analyzing a year where noteworthy emission changes are expected to occur, impacts can be estimated using emission changes from a year as near as possible to the year of noteworthy emissions change. A desktop version of the analytical tool may also be used.

Environmental Justice Analysis, and to encourage consideration of these impacts in the utility's decision on the PCA.

h) For resources located within the nonattainment areas (or an area that may be designated nonattainment based on reasonably known information at the time of filing) in the electric utility service territory, identify and assess their impact to the nonattainment status for portfolio #2, listed above, as compared to portfolio #1, and qualitatively support in testimony. The assessment should consider all nonattainment pollutants (i.e., SO_2 and ozone), as well as their precursors (i.e., NO_x and VOCs); and

i) Narrative discussion of the quantitative and qualitative health and environmental impacts, based on the analysis above, methodologies, data sources, and related observations. Explain how these considerations were taken into account in the utility's decision. Discuss changes in health, safety, and welfare of individuals in environmental justice communities from the PCA as compared to the alternatives considered, including siting considerations for any proposed new generation.

XXIV. Exhibits and Workpapers: The filing shall include exhibits and workpapers as outlined below, subject to any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.

a) The Company shall include an exhibit containing a table that designates where each filing requirement is included within its testimony, exhibits, and workpapers, with appropriate page and section numbers;

b) The Company shall include an exhibit that depicts a stacked bar graph that includes the RTO capacity credit of all existing resources and new resources for all required scenarios, sensitivities, and any pertinent utility-proposed scenarios, color designated by resource type, in each of the planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin;

c) The Company shall include an exhibit of stacked bar graphs that include the energy expected to be produced by all existing resources, new resources, and market purchases for each planning year and for all MIRPP required scenarios and sensitivities. Each graph shall be color designated by resource type. Each graph shall have a line representing expected demand over the length of the planning period;

d) Include a chart that compares the total projected carbon emissions under each required scenario to the relevant sensitivities and build plans under that scenario, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify which of the carbon accounting methodologies it used for all scenarios and sensitivities. The methodology should be one identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases or other Commission approved methodology;[14]

    1. Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact;

e) Any modeling input and output files used in developing the application, supporting testimony, resource plan, and any alternative plans. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependent binary format should be made available to parties that obtain a license;

    1. Cost data, estimates, and co-benefit analyses that were used in the resource screening process or in any other way to determine resource selection of each resource that was considered either individually or in combination with other resources constructed as a single facility, including DERs, storage, and renewable energy resources;

f) A description, including estimated costs, of each alternative proposal received by the utility;

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[14] Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases, https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019.

g) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery plan proceeding;

h) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences;

    1. Present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws, and rules. Included with this information, the utility shall analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet;
    2. Estimated annual emissions of CO_2 and greenhouse gases, particulates, SO_2, NO_x, and Hg per year and over the study period of the facilities included in their IRP;
    3. The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates; and
    4. Other documents and data underlying the IRP and CEP analysis.

Appendix 1: Acronym List

BenMAP-CE: Benefits Mapping and Analysis Program- Community Edition

CO: Carbon Monoxide

COBRA: Co-Benefits Risk Assessment

CON: Certificate of Necessity

CO_2: Carbon Dioxide

DER: Distributed Energy Resources

DR: Demand Response

EGLE: Department of Environment, Great Lakes, and Energy

EJ: Environmental Justice

EJ SCREEN: Environmental Justice Screening and Mapping Tool

EWR: Energy Waste Reduction

Hg: Mercury

IRP: Integrated Resource Plan

ISO: Independent System Operator

kW: Kilowatt

kWh: Kilowatt-hour

LRZ: Local Resource Zone

MiEJScreen: Michigan Environmental Justice Screening Tool

MIRPP: Michigan Integrated Resource Planning Parameters

MPSC: Michigan Public Service Commission or Commission

MW: Megawatts

MWh: Megawatt Hour

NO_x: Nitrogen Oxide

NPVRR: Net Present Value Revenue Requirement

NWA: Non-Wire Alternative

O&M: Operation and Maintenance

Pb: Lead

PCA: Proposed Course of Action

PM: Particulate Matter

PPA: Power Purchase Agreement

REC: Renewable Energy Credit

RFP: Request for Proposalaf

RTO: Regional Transmission Organization

SO_2: Sulfur Dioxide

Staff: Commission Staff

USEPA: United States Environmental Protection Agency

VOC: Volatile Organic Compounds

ZRC: Zonal Resource Credit

Appendix 2: Example Affordability Methodology

1. Calculate the projected rate and expected annual bill impact for the residential customer class for each year of the PCA using the most recently approved cost of service study. Annual cost adjustments shall reflect a rate of inflation at the time of filing.
2. Calculate the expected average annual energy cost for residential customers by household using publicly available data such as the U.S. Energy Information Administration's Residential Energy Consumption Survey and forecast in nominal dollars for the first five years of the PCA. Annual cost adjustments shall reflect a rate of inflation at the time of filing.
3. Create an income distribution of the utility's service territory using publicly available data, such as B19001 Household Income in the Past 12 Months census data. Incomes for the first five years of the plan will be presented in nominal dollars and shall reflect a rate of inflation at the time of filing.
4. Calculate the expected impact of the PCA on Michigan households within the utility service territory by adding the annual bill impact of the PCA in (1), to a residential household's expected average annual energy cost in (2), for the first five years of the plan.
5. Based on the results of (4), calculate the expected energy burden percentage for each income range of the income distribution in (3) for the first five years of the plan.

Clean Energy Plan
Filing Requirements
for Rate-Regulated Electric Utilities

Pursuant to Public Act 295 of 2008 as amended by Public Act 235 of 2023, Section 51

December 18, 2025

Introduction

PA 235 of 2023 was signed into law by Governor Whitmer on November 21, 2023. Section 51 directs the following:

1) As a clean energy standard, an electric provider shall achieve a clean energy portfolio of at least the following:

(a) In 2035 through 2039, 80%.

(b) In 2040 and each year thereafter, 100%.

An electric provider whose rates are regulated by the commission shall include a clean energy plan (CEP) illustration of how it intends to comply with the clean energy standard as part of that electric provider's integrated resource plan.

Application Instructions for Clean Energy Plan Filings

These application instructions apply to an investor-owned rate-regulated electric utility application for Michigan Public Service Commission (MPSC or Commission) approval of a Clean Energy Plan (CEP) under the provisions of MCL 460.1051. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the utility may also be included in the application.

Filing Announcement

To facilitate the scheduling and preparation of CEP filings, a rate regulated utility who intends to file a CEP, shall combine its CEP filing announcement with its IRP filing announcement necessary for its integrated resource plan filing. The CEP portion of the filing announcement shall include:

a) Statement of intent to file a CEP;
b) Estimated date of filing;
c) Any information related to any public engagement that has already taken place or is scheduled to take place.

Participant Engagement and Public Outreach Process

Participant engagement early in the development of the CEP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. Utilities should engage participants in the development of the CEP and IRP simultaneously. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision making for the CEP filing.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes. Many of these definitions are taken directly from Public Act 235 of 2023.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Environmental Justice Communities – Refers to overburdened, vulnerable, underserved or disadvantaged communities that are identified, for the purpose of this analysis, by a minimum percentile of 75 in the Michigan Environmental Justice Screening Tool (MiEJScreen) or a minimum percentile of 75 in either the Low-Income Population or Black, Indigenous, People of Color population layer. If MiEJScreen tool is not available, the utility should work with and take feedback from Staff, EGLE, and interested parties when determining which other tool or methodology to use.

Greenhouse Gas Emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride

Carbon Capture and Storage - A process that involves collecting carbon dioxide at its source and storing, or sequestering, it to prevent its release into the atmosphere.[1]

[1] Public Act 295 of 2008 as amended by Public Act 235 of 2023.

Direct Air Capture and Storage – A process that involves removing CO2 directly from the atmosphere and storing or sequestering it.

Clean Energy - electricity or steam generated using a clean energy system. [2]

Clean Energy Plan - An electric provider's plan to meet the clean energy standard approved under section 51.[3]

Clean Energy Portfolio - The percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy.[4]

Clean Energy Standard - The clean energy portfolio required in Public Act 295 as amended by Public Act 341 under section 51(1).[5]

Clean Energy System - An electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:[6]

i) Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

ii) Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of Environment, Great Lakes, and Energy determines, through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

iii) Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph 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

[2] Public Act 295 of 2008 as amended by Public Act 235 of 2023.
[3] Et al.
[4] Et al.
[5] Et al.
[6] Et al.

carbon capture and sequestration and other available applications, including, but not limited to, carbon removal technologies. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

iv) Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision.

CEP Filing, Data, and Documentation

The utility's CEP filing shall demonstrate compliance with MCL 460.1051. All assumptions and inputs shall be applied consistently in both CEP and IRP plans. The statute requires that rate regulated utilities file a CEP with its IRP. Rate-regulated utilities need not duplicate information that is contained within the IRP. Both CEPs and IRPs are expected to be filed in the same filing and therefore, information should simply be identified as applying to both plans. CEP filings shall include the following items:

a) Letter of transmittal expressing commitment to the approved clean energy plan signed by an officer of the utility having the authority to commit the utility to the clean energy plan, acknowledging that the utility reserves the right to make changes to its clean energy plan as appropriate due to changing circumstances;
b) Any technical volume(s) that are necessary to fully describe and document the utility's analysis and decisions in selecting its clean energy plan and resources therein;
c) The data and information requested in the Commission's CEP Filing Requirements included herein;
d) Any request for an extension pursuant to MCL 460.1051 (2)(b); and
e) Any other information deemed relevant by the utility.

To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with the provided outline and include at least the following items:

I. Summary: A CEP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The summary shall include the following:

a) An overview of the planning period examined in the CEP application;
b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy;
c) A summary of any analytical approach used in the utility's analysis and the types of new resources considered;
d) A description of how environmental justice (EJ), and overall affordability were considered when selecting the proposed clean energy systems that will be used to meet the clean energy standard;
e) The Company shall include a figure that depicts a stacked bar graph that includes the annual energy expected to be produced by all resources used for compliance for each year of the planning horizon as compared to its sales forecast for each corresponding year over the planning period. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period. The graph should also depict the utility's progress toward or achievement of State goals of 80% clean energy in 2035-2039 and 100% clean energy in 2040 and each year thereafter; and
f) Any other information that would aid the public understanding of the utility's proposed plan.

II. Clean Energy Plan Details: The utility shall describe resource plans that it intends to use to satisfy at least the objectives and priorities identified in MCL 460.1051, its CEP planning process, and any public engagement. If a utility is proposing to include a natural gas generation facility that includes carbon capture and storage as a CES, the utility shall provide sufficient evidence to demonstrate that the facility meets the requirements of MCL 460.1003(i(ii).

III. Renewables and Renewable Portfolio Standards Requirements: Projected energy purchased or produced by the utility from renewable energy resources. Describe how the utility will meet existing renewable energy standards including evidence that

illustrates consistency with the utility's REP. The utility shall also discuss any key differences between its REP and CEP.[7,8]

IV. Total Electric Sales Forecast: A long-term forecast of the electric provider's total electric sales. To ensure compliance with the CEP the electric provider should consider the following when developing its forecast:
   a) DER adoption and impacts to the overall electric sales in the electric provider's service territory;
   b) Electric vehicle adoption assumptions and impacts to overall total electric sales;
   c) Electrification adoption assumptions and impacts to overall electric sales forecasts.

V. Proposed Clean Resource Plan: Include a detailed description of:
   a) The type of clean generation technologies being used to meet compliance.
   b) The impact of the CEP on the diversity of the utility resource portfolio. Include details in a qualitative discussion.

VI. If the utility is requesting an extension of its plan pursuant to MCL 460.1051 (2)(b), provide detailed information for the reason that an extension is being requested. Include data to support the request.

VII. The utility shall describe the process used to select the proposed resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk.

VIII. Include a completed template consistent with the example in Appendix A.

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[7] For the purposes of illustrating how the electric provider intends to reach compliance, 1 REC = 1 MWh of clean energy. Banked and bonus RECs may also be used to meet the Clean Energy Standard whereby 1 REC is used (retired) to meet 1 MWh of the clean energy standard requirement. The electric provider's future renewable energy plan filings should reflect the retirement of these additional RECs.

[8] It should be noted that REP resources can qualify for CEP compliance, but not all resources that qualify for CEP compliance qualify for REP compliance.

IX. The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule and description of actions to implement ongoing and planned demand-side programs;

b) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction.

Clean Energy Plan Filing Requirements for Municipalities

Pursuant to Public Act 295 of 2008 as amended by Public Act 235 of 2023, Section 51

December 18, 2025

Introduction

PA 235 of 2023 was signed into law by Governor Whitmer on November 21, 2023. Section 51 directs the following:

1) As a clean energy standard, an electric provider shall achieve a clean energy portfolio of at least the following:

(a) In 2035 through 2039, 80%.

(b) In 2040 and each year thereafter, 100%.

All municipalities shall file a proposed clean energy plan (CEP) with the Commission by July 1, 2028. Two or more municipally owned electric utilities may file jointly.

Application Instructions for Clean Energy Plan Filings

These application instructions apply to a municipality's application for Michigan Public Service Commission (MPSC or Commission) approval of a Clean Energy Plan under the provisions of MCL 460.1051. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the municipal utility may also be included in the application.

Filing Announcement

To facilitate the scheduling and preparation of CEP filings, municipal utilities are required to file a CEP on or before their respective dates shown above and shall include a filing announcement. The announcement shall be filed in a new docket at least 30 calendar days prior to the proposed filing.

The filing announcement shall include:

a) Statement of intent to file a CEP and whether the municipality plans to file the CEP with the REP;

b) Estimated date of filing;

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes. Many of these definitions are taken directly from Public Act 235 of 2023.

Distributed Energy Resource - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) include both generators and energy storage technologies capable of exporting active power to a distribution system.

Greenhouse Gas Emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride

Clean Energy - electricity or steam generated using a clean energy system.[1]

Clean Energy Plan - An electric provider's plan to meet the clean energy standard approved under section 51.[2]

Clean Energy Portfolio - The percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy.[3]

Clean Energy Standard - The clean energy portfolio required in Public Act 295 as amended by Public Act 341 under section 51(1).[4]

Clean Energy System - An electricity generation facility or system or set of electricity generation systems that meets any of the following requirements:[5]

(i) Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

(ii) Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of Environment, Great Lakes, and Energy determines, through a facility-specific major source permitting analysis, consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

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[1] Public Act 295 of 2008 as amended by Public Act 235 of 2023

[2] Et al.

[3] Et al.

[4] Et al.

[5] Et al.

(iii) Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph 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. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

(iv) Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision.

CEP Filing, Data, and Documentation

The municipal utility's CEP filing shall demonstrate compliance with MCL 460.1051. The CEP filings shall include the following items:

a) The data and information requested in the Commission's CEP Filing Requirements included herein;
b) Any request for an extension pursuant to MCL 460.1051 (4)(g); and
c) Any other information deemed relevant by the municipality.

The municipal utility's CEP filing shall include a CEP document(s) and application information that describes the municipal utility's portfolio for complying with the clean energy plan and resources therein. To facilitate a similar format for municipal application, the municipal utility is encouraged to align its filing with the provided outline and include at least the following items:

I. Summary: An overview of the planning period, including a summary of the CEP, and including a description of the projected transition from the current resource portfolio to the future resource portfolio. The municipal utility is encouraged to include any other

information that would aid the public or Commission's understanding of the municipality's proposed plan.

II. A description of how the municipal utility's plan will satisfy at least the objectives and priorities identified in MCL 460.1051.

III. If a municipal utility board has granted an extension of its plan, pursuant to MCL 460.1051(4)(g), provide detailed information about the reason(s) that an extension was granted. Include data that supports the extension.

IV. Include a completed template consistent with the example in Appendix A.

V. A description of the municipal utility's implementation plan that specifies, to the extent practically known, key milestones necessary to implement the proposed resource plan over the planning period for both demand-side and supply-side resources included in the plan.

Clean Energy Plan Filing Requirements for Electric Cooperatives and Alternative Energy Suppliers

Pursuant to Public Act 295 of 2008 as amended by Public Act 235 of 2023, Section 51

December 18, 2025

Introduction

PA 235 of 2023 was signed into law by Governor Whitmer on November 21, 2023. Section 51 directs the following:

1) As a clean energy standard, an electric provider shall achieve a clean energy portfolio of at least the following:

(a) In 2035 through 2039, 80%.

(b) In 2040 and each year thereafter, 100%.

All alternative electric suppliers (AES) and cooperative electric suppliers within Michigan shall file a Clean Energy Plan (CEP) on or before January 1, 2028. If electric providers file jointly for renewable energy plans, the same electric providers may file a CEP jointly.

Application Instructions for Clean Energy Plan Filings

These application instructions apply to an AES and cooperative electric suppliers' application for Michigan Public Service Commission (MPSC or Commission) approval of a Clean Energy Plan under the provisions of MCL 460.1051. The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the electric provider may also be included in the application.

Filing Announcement

To facilitate the scheduling and preparation of CEP filings, electric cooperatives and AESs are required to file a CEP on or before their respective dates shown above, shall include a filing announcement. The announcement shall be filed in a new docket at least 30 calendar days prior to the proposed filing.

The filing announcement shall include:

a) Statement of intent to file a CEP;

b) Estimated date of filing;

Participant Engagement and Public Outreach Process

It is encouraged that each cooperative and AES host a webpage where the electric provider’s customers or members, community action agencies, and community leaders can review a draft

version of the CEP. The webpage should allow for the ability for interested persons to submit comments regarding the CEP. The webpage should be maintained on a website in an accessible location for the duration of the outreach process and the duration of the CEP case, until a final commission order is published. The electric cooperative or AES may incorporate the comments it received in its filing. If an alternative outreach plan was used by the load serving entity, details should be provided.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes. Many of these definitions are taken directly from Public Act 235 of 2023.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. Distributed Energy Resources (DER) includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Greenhouse Gas Emissions - carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, or sulfur hexafluoride

Clean Energy - electricity or steam generated using a clean energy system. [1]

Clean Energy Plan - An electric provider's plan to meet the clean energy standard approved under section 51.[2]

Clean Energy Portfolio - The percentage of an electric provider's total retail electric sales consisting of clean energy or renewable energy.[3]

Clean Energy Standard - The clean energy portfolio required in Public Act 295 as amended by Public Act 341 under section 51(1).[4]

Clean Energy System - An electricity generation facility or system or set of electricity generation systems that meets any of the following requirements[5]:

i) Generates electricity or steam without emitting greenhouse gas, including nuclear generation.

[1] Et al.
[2] Et al.
[3] Et al.
[4] Public Act 295 of 2008 as amended by Public Act 235 of 2023.
[5] Et al.

ii) Is fueled by natural gas and uses carbon capture and storage that is at least 90% effective in capturing and permanently storing carbon dioxide. If the department of Environment, Great Lakes, and Energy determines, through a facility-specific major source permitting analysis consistent with applicable United States Environmental Protection Agency rules, that a capture rate higher than 90% meets the best available control technology standard, as applicable, that higher percentage shall be used instead of 90% for facilities permitted after the effective date of the amendatory act that added section 51. Using carbon dioxide for enhanced oil recovery is not considered to be permanent storage for the purposes of this subparagraph.

iii) Is an independently owned combined cycle power plant fueled by natural gas that has a power purchase agreement with an electric provider as of the effective date of the amendatory act that added this subparagraph 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. In reviewing and approving a plan submitted under this subparagraph, the commission shall consider best available technology and applications as well as rate affordability, resource adequacy, and grid reliability.

iv) Is defined as a clean energy system in rules adopted by the commission consistent with the purposes of this subdivision.

CEP Filing, Data, and Documentation

The electric provider's CEP filing shall demonstrate compliance with MCL 460.1051. The CEP filings shall include the following items:

a) Letter of transmittal expressing commitment to the clean energy plan signed by an officer of the electric provider having the authority to commit the electric provider to the clean energy plan, acknowledging that the electric provider reserves the right to make changes to its clean energy plan as appropriate due to changing circumstances;

b) The data and information requested in the Commission's CEP Filing Requirements included herein;
c) Any request for an extension pursuant to MCL 460.1051(3) (g); and
d) Any other information deemed relevant by the electric provider.

The electric provider's CEP filing shall include a CEP document(s) and application information that describes the electric provider's portfolio of resources it intends to use for complying with the clean energy plan and resources therein. To facilitate a similar format for each electric provider's application, the electric provider is encouraged to align its filing with the provided outline and include at least the following items:

I. Summary: A CEP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall summarize the contents of the CEP document and shall include the following:

a) An overview of the planning period examined in the CEP application;
b) An overview of how the AES plans to transition from its current resource portfolio to its future resource portfolio.
c) Any other information that would aid the public understanding of the electric provider's proposed plan.

II. Describe how the electric provider plans to satisfy at least the objectives and priorities identified in MCL 460.1051. If a utility is proposing to include a natural gas generation facility that includes carbon capture and storage as a CES, the utility shall provide sufficient evidence to demonstrate that the facility meets the requirements of MCL 460.1003(i(ii).

III. Renewables and Renewable Portfolio Standards Requirements: Projected energy purchased or produced by the electric provider from renewable energy resources. Describe how the electric provider will meet existing renewable energy standards

including evidence that illustrates consistency with the electric provider's REP. The electric provider shall also discuss any key differences between its REP and CEP.[6,7]

IV. If an AES is requesting an extension of its plan pursuant to MCL 460.1051 (b), provide detailed information for the reason that an extension is being requested. Include data to support the request. If the governing body of an electric cooperative has granted an extension, please provide details about that grant.

V. Include a completed template consistent with the example in Appendix A.

VI. The electric provider shall develop an implementation plan that specifies the milestones necessary to implement the proposed resource plan over the implementation period. The electric provider shall describe and document its implementation plan, which shall contain:

a) Any proposed schedule and description of actions to implement ongoing and planned demand-side programs necessary to align with the electric provider's sales forecast;

b) A proposed schedule and description of relevant supply-side resources necessary for compliance and include milestones such as research, engineering, retirement, acquisition, and construction.

[6] For the purposes of illustrating how the electric provider intends to reach compliance, 1 REC = 1 MWh of clean energy. Banked and bonus RECs may also be used to meet the Clean Energy Standard whereby 1 REC is used (retired) to meet 1 MWh of the clean energy standard requirement. The electric provider's future renewable energy plan filings should reflect the retirement of these additional RECs.

[7] It should be noted that REP resources can qualify for CEP compliance, not all resources that qualify for CEP compliance qualify for REP compliance.

EXHIBIT F

Appendix A: Clean Energy Plan Template

Line No.	Electric Sales (MWh)		Example	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
1	Method: Weather Normalized or 3 Year Average*																						
2	If Selected Weather Normalized:																						
3	Current Year Sales to Retail Customers																						
4	Current Year Weather Normalization Factor																						
5	Current Year Weather Normalized Sales																						
6	If Selected 3 Year Average:																						
7	Current Year Retail Sales to Retail Customers		100,000,000																				
8	Prior Year #1 Retail Sales to Retail Customers		98,000,000																				
9	Prior Year #2 Retail Sales to Retail Customers		102,000,000																				
10	3 Year Average of sales	(line7+line8+line9)/3	100,000,000																				
11	Clean Energy Standard Requirement (MWh)																						
12	Company Owned Renewable Energy (MWh) less Voluntary Green Pricing		35,000,000																				
13	Renewable Energy Power Purchase Agreements (MWh) less Voluntary Green Pricing		15,000,000																				
14	Distributed Generation Outflow-Based upon prior year (MWh)		10,000,000																				
15	Voluntary Green Pricing-Based upon prior year (MWh)		10,000																				
16	Purchased REC's (5% thru 2035)		0																				
17	RECs reported and retired pursuant to MCL 460.1029 (4)		50,000																				
18	Banked RECs Projected to be used for CEP Compliance**		20,000,000																				
19	Company Owned Nuclear Energy (MWh)		0																				
20	Other Company Owned Clean Energy System Generation (MWh) (Excluding resources already included in line 13)		0																				
21	Clean Energy System Power Purchase Agreements (MWh) (Excluding resources already included in line 14)		0																				
22	Total Clean Energy System Generation (MWh)	Sum of Lines 12 thru 21	80,060,000																				
23	Clean Energy Percentage Achieved Annually																						
24	Percentage Achieved Annually	(line23/line 3 or 10)*100	80%																				

*Note: The electric provider's REP and CEP should use the same retail sales calculation; either weather normalized or the 3 year average.

**Note: 1 Renewable Energy Credit (REC) is equivlant to 1MWh of renewable energy. If a REC is to count toward meeting the Clean Energy Standard for a given year, it must be retired in that year.

P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-21867 et al

County of Ingham)

Brianna Brown being duly sworn, deposes and says that on December 18, 2025 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Brianna Brown

Subscribed and sworn to before me
this 18th day of December 2025.

Angela P. Sanderson
Notary Public, Shiawassee County, Michigan
As acting in Eaton County
My Commission Expires: May 21, 2030

Service List for Case: U-21867

Name	On Behalf Of	Email Address
Karsten Szajner	MPSC Staff	szajnerk@michigan.gov

GEMOTION DISTRIBUTION SERVICE LIST

kabraham@mpower.org	Abraham,Katie - MMEA
mkuchera@AEPENERGY.COM	AEP Energy
mfurmanski@algerdelta.com	Alger Delta Cooperative
akellen@wppienergy.org	Alger Delta Cooperative
kd@alpenapower.com	Alpena Power
dgreen@alpenapower.com	Alpena Power
VSTRetailReg@VistraCorp.com	Ambit Midwest, LLC
kerdmann@atcllc.com	American Transmission Company
acotter@atcllc.com	American Transmission Company
john.calhoun@ardentnaturalgas.com	Ardent Natural Gas, LLC
awebster@baycitymi.gov	Bay City Electric Light & Power
sara.anderson@bayfieldelectric.com	Bayfield Electric
rbishop@BISHOPENERGY.COM	Bishop Energy
braukerL@MICHIGAN.GOV	Brauker, Linda
cherie.fuller@bp.com	BP Energy Retail Company, LLC
christine.hughey@bp.com	BP Energy Retail Company LLC
greg.bass@calpinesolutions.com	Calpine Energy Solutions
lachappelle@varnumlaw.com	Chappelle, Laura
manderson@wpsci.com	Cherryland Electric
mengels@wpsci.com	Cherryland Electric
cdrys@wpsci.com	Cherryland Electric
ljohnson@wpsci.com	Cherryland Electric
rjohnson@cherrylandelectric.coop	Cherryland Electric Cooperative
frucheyb@DTEENERGY.COM	Citizens Gas Fuel Company
crystalfallsmgr@HOTMAIL.COM	City of Crystal Falls
gpirkola@escanaba.org	City of Escanaba
jolson@gladstonemi.gov	City of Gladstone
kmaynard@cityofmarshall.com	City of Marshall
tdavlin@portland-michigan.org	City of Portland
cwilson@cloverland.com	Cloverland Electric
mheise@cloverland.com	Cloverland Electric
todd.mortimer@CMSENERGY.COM	CMS Energy
Kenneth.Johnston@cmsenergy.com	Consumers Energy
Yong.Keyes@cmsenergy.com	Consumers Energy
chibuzo.obikwelu@cmsenergy.com	Consumers Energy
sarah.jorgensen@cmsenergy.com	Consumers Energy Company
Michael.torrey@cmsenergy.com	Consumers Energy Company
CANDACE.GONZALES@cmsenergy.com	Consumers Energy Company
mpsc.filings@CMSENERGY.COM	Consumers Energy Company
mpsc.filings@CMSENERGY.COM	Consumers Energy Company
david.fein@CONSTELLATION.COM	Constellation Energy
kate.stanley@CONSTELLATION.COM	Constellation Energy
kate.fleche@CONSTELLATION.COM	Constellation New Energy

GEMOTION DISTRIBUTION SERVICE LIST

choicecompliance@constellation.com	Constellation New Energy Inc
lpage@dickinsonwright.com	Dickinson Wright
shaundillon@dillonenergy.com	Dillon Energy Services
info@dillonpower.com	Dillon Power, LLC
Neal.fitch@nrg.com	Direct Energy
Kara.briggs@nrg.com	Direct Energy
Ryan.harwell@nrg.com	Direct Energy
bryce.mckenney@nrg.com	Direct Energy
stephen.lindeman@dteenergy.com	DTE Energy
karl.lievense@dteenergy.com	DTE Energy
konstantin.korolyov@dteenergy.com	DTE Energy
mpscfilings@DTEENERGY.COM	DTE Energy
joyce.leslie@dteenergy.com	DTE Energy
karen.vucinaj@dteenergy.com	DTE Energy
customerservice@eligoenergy.com	Eligo Energy MI, LLC
regulatory@eligoenergy.com	Eligo Energy MI, LLC
frank.travaglione@vistracorp.com	Energy Harbor
rfawaz@energyintl.com	Energy International Power Marketing d/b/a PowerOne
sejackinchuk@varnumlaw.com	Energy Michigan
michael.reiss@engie.com	Engie Gas & Power LLC
customercare@plymouthenergy.com	ENGIE Gas & Power f/k/a Plymouth Energy
VSTRetailReg@VistraCorp.com	Everyday Energy, LLC d/b/a Energy Rewards
felicel@MICHIGAN.GOV	Felice, Lisa
bgorman@FIRSTENERGYCORP.COM	First Energy
phil@allendaleheating.com	Forner, Phil
dburks@glenergy.com	Great Lakes Energy
manderson@wpsci.com	Great Lakes Energy
mengels@wpsci.com	Great Lakes Energy
cdrys@wpsci.com	Great Lakes Energy
ljohnson@wpsci.com	Great Lakes Energy
slamp@glenergy.com	Great Lakes Energy Cooperative
sculver@glenergy.com	Great Lakes Energy Cooperative
johnm@gogreenlightenergy.com	Greenlight Energy Inc.
lrgustafson@CMSENERGY.COM	Gustafson, Lisa
jhammel@hillsdalebpu.com	Hillsdale Board of Public Utilities
coneill@homeworks.org	HomeWorks Tri-County Electric Cooperative
psimmer@HOMEWORKS.ORG	HomeWorks Tri-County Electric Cooperative
bmcbride@aep.com	Indiana Michigan Power
mgobrien@aep.com	Indiana Michigan Power Company
dan@megautilities.org	Integrys Group
daustin@IGSENERGY.COM	Interstate Gas Supply Inc
michael.nugent@igs.com	Interstate Gas Supply d/b/a IGS Energy
general@itctransco.com	ITC Holdings
cmarshall@itctransco.com	ITC Holdings
apascaris@itctransco.com	ITC Holdings

GEMOTION DISTRIBUTION SERVICE LIST

vanesetti@justenergy.com	Just Energy of Michigan Corporation
igoodman@commerceenergy.com	Just Energy Solutions
krichel@DLIB.INFO	Krichel, Thomas
dbodine@LIBERTYPOWERCORP.COM	Liberty Power
ham557@GMAIL.COM	Lowell S.
tjlundgren@varnumlaw.com	Lundgren, Timothy
tcarpenter@mblp.org	Marquette Board of Light & Power
regulatory@medianenergy.com	Median Energy Corporation
suzy@megautilities.org	MEGA
dan@megautilities.org	MEGA
mmann@USGANDE.COM	Michigan Gas & Electric
VSTRetailReg@VistraCorp.com	Michigan Gas & Electric (US Gas & Electric)
shannon.burzycki@wecenergygroup.com	Michigan Gas Utilities Corporation
mrzwiers@INTEGRYSGROUP.COM	Michigan Gas Utilities/Upper Penn Power/Wisconsin
kabraham@mpower.org	Michigan Public Power Agency
info@michigannaturalgasllc.com	Michigan Natural Gas, LLC
JHDillavou@midamericanenergyservices.com	MidAmerican Energy Services, LLC
JCAltmayer@midamericanenergyservices.com	MidAmerican Energy Services, LLC
LMLann@midamericanenergyservices.com	MidAmerican Energy Services, LLC
manderson@wpsci.com	Midwest Energy
mengels@wpsci.com	Midwest Energy
cdrys@wpsci.com	Midwest Energy
ljohnson@wpsci.com	Midwest Energy
dave.allen@TEAMMIDWEST.COM	Midwest Energy Cooperative
terry.rubenthaler@teammidwest.com	Midwest Energy Cooperative
kerri.wade@teammidwest.com	Midwest Energy Cooperative
Marie-Rose.Gatete@teammidwest.com	Midwest Energy Cooperative
meghan.tarver@teammidwest.com	Midwest Energy Cooperative
d.motley@COMCAST.NET	Motley, Doug
rarchiba@FOSTEROIL.COM	My Choice Energy
customerservice@nordicenergy-us.com	Nordic Energy Services, LLC
regulatory@nordicenergy-us.com	Nordic Energy Services, LLC
karl.j.hoesly@xcelenergy.com	Northern States Power
sarah.m.frazee@xcelenergy.com	Northern States Xcel
kbeattie@ntherm.com	nTherm, LLC
daho@ontorea.com	Ontonagon County Rural
esoumis@ontorea.com	Ontonagon County Rural Electric
regulatory@indraenergy.com	PALMco Energy MI, LLC d/b/a Indra Energy
mpauley@GRANGERNET.COM	Pauley, Marc
mmpeck@fischerfranklin.com	Peck, Matthew
bschlansker@PREMIERENERGYLLC.COM	Premier Energy Marketing LLC
manderson@wpsci.com	Presque Isle

GEMOTION DISTRIBUTION SERVICE LIST

mengels@wpsci.com	Presque Isle
cdrys@wpsci.com	Presque Isle
ljohnson@wpsci.com	Presque Isle
MVanschoten@pieg.com	Presque Isle Electric & Gas Cooperative, INC
aberg@pieg.com	Presque Isle Electric & Gas Cooperative, INC
yesterdae@getprovision.com	Provision Power & Gas, LLC
johnbistranin@realgy.com	Realgy Corp.
BusinessOffice@REALGY.COM	Realgy Energy Services
akeilson@genieretail.com	Residents Energy LLC
btrombino@rpaenergy.com	RPA Energy d/b/a Green Choice Energy
mvorabouth@ses4energy.com	Santana Energy
rabaey@SES4ENERGY.COM	Santana Energy
ttynes@ses4energy.com	Santanna Natural Gas Corporation
trish.mcfadin@southstarenergy.com	SouthStar d/b/a Grand Rapids Energy
kejoseph@sparkenergy.com	Spark Energy Gas, LP
cborr@WPSCI.COM	Spartan Renewable Energy, Inc. (Wolverine Power Marketing Corp)
jbelec@stephenson-mi.org	Stephenson Utilities Department
kay8643990@YAHOO.COM	Superior Energy Company
legal@symmetryenergy.com	Symmetry Energy Solutions, LLC
regulatory@texasretailenergy.com	Texas Retail Energy, LLC
agilbert@cleanskyenergy.com	Tital Gas, LLC d/b/a CleanSkyEnergy
bessenmacher@tecmi.coop	Thumb Electric Cooperative
president@tomorrowenergy.com	Tomorrow Energy Corporation
manderson@wpsci.com	Tri-County Electric
mengels@wpsci.com	Tri-County Electric
cdrys@wpsci.com	Tri-County Electric
ljohnson@wpsci.com	Tri-County Electric
mlindsay@uetllc.com	United Energy Trading d/b/a Kratos Gas & Power
colleen.sipiorski@wecenergygroup.com	Upper Michigan Energy Resources Corporation
djmier@integrysgroup.com	Upper Michigan Energy Resources Corporation
James.Beyer@wecenergygroup.com	Upper Michigan Energy Resources Corporation
Richard.Stasik@wecenergygroup.com	Upper Michigan Energy Resources Corporation
nbell@uppco.com	Upper Peninsula Power Company
jformol@uppco.com	Upper Peninsula Power Company
ghaehnel@uppco.com	Upper Peninsula Power Company
estocking@uppco.com	Upper Peninsula Power Company
manager@villageofbaraga.org	Village of Baraga
Villagemanager@villageofclinton.org	Village of Clinton
VSTRetailReg@VistraCorp.com	Viridian Energy PA, LLC
jeinstein@volunteerenergy.com	Volunteer Energy Services
leew@WVPA.COM	Wabash Valley Power
melissa.schauer@wecenergygroup.com	We Energies
andrew.miller1@wecenergygroup.com	We Energies
melissa.schauer@wecenergygroup.com	Wisconsin Public Service

GEMOTION DISTRIBUTION SERVICE LIST

andrew.miller1@wecenergygroup.com	Wisconsin Public Service
tking@WPSCI.COM	Wolverine Power
jbaumann@wpsci.com	Wolverine Power
cborr@wpsci.com	Wolverine Power
ddecouer@wpsci.com	Wolverine Power
bvalice@wpsci.com	Wolverine Power
Amanda@misostates.org	Wood, Amanda
Deborah.e.erwin@xcelenergy.com	Xcel Energy
Michelle.Schlosser@xcelenergy.com	Xcel Energy
bryce.mckenney@nrg.com	Xoom Energy Michigan, LLC d/b/a Xoom Energy