Michigan Public Service Commission

MI Power Grid:

Phase III Advanced Planning Processes

Feedback from December 16, 2021
Stakeholder Meeting

LARA
LICENSING AND REGULATORY AFFAIRS

Consumers Energy
Count on Us®

January 6, 2022

VIA E-MAIL at GibbsK2@Michigan.gov

RE: Consumers Energy Comments to Staff on Michigan Integrated Resource Planning Parameters ("MIRPP") and Integrated Resource Plan ("IRP") Filing Requirements

Dear Ms. Gibbs:

The Company appreciates Staff's efforts leading the Advanced Planning Phase III workgroup collaborative discussions on December 16, 2021. The Company thanks Staff for their efforts in developing the draft MIRPP and IRP Filing Requirements, and for providing the opportunity for discussion and comment.

The Company requests consideration of the attached redline documents, and the following comments in response to Staff prompts:

1. Please provide any feedback supporting or suggesting changes to Staff's proposed MIRPP.

Please reference the attached Draft MIRPP redline document for feedback and recommended updates.

In conjunction with the provided redline, Consumers Energy would like to expand on the following feedback:

a. MISO Futures Alignment – elements of the current draft Base and Electrification and Decarbonization scenarios appear to be taken directly from MISO Futures 1 and 3. More discussion and clarification is needed around how the MIRPP scenarios are to align or replicate the MISO Futures process before additional feedback can be provided. In addition, it is unclear how an individual utility is to model an IRP for their service territory when using data and forecasts (for example, load forecasts) that were created and designed for all of MISO. The Company has made suggested redlines and adjustments to the attached MIRPP document to clarify utility specific IRP assumptions while still aligning with the MISO Futures process. Further clarification is requested as to whether the 2021 or 2022 MISO Futures would be used, or if a utility would use a "most recent" MISO Futures publication. If "most recent" is utilized, it is unclear how changes to MISO's Future outlooks will impact various utility filings.

b. The proposed MIRPP dictates several specific inputs to the MISO regional modeling assumptions. By specifying several assumptions must be consistent with MISO Futures, the MPSC is requiring utilities in Michigan to develop models with highly specific and prescriptive inputs to the MISO regional data. Utilities in Michigan have various and differing methods for modeling of the non-utility footprint; the proposed MIRRP changes will require more detailed development and Staff review to ensure consistency with MISO Futures.

c. The underlying assumptions of how MISO determined incorporation of 100% of utility integrated resource plan announcements and 85% (or 100%) of state and utility goals and announcements that are not legislated is not clear. Instead of including this line in the description of the Scenarios, the Company proposes to use the **retirement assumptions** resulting from MISO's determination of state and utility goals at the respective percentage achievements. Further, any retirements defined in the MISO Futures could be updated with more recent public announcements.

d. The description in Scenario 1 states that "an annual energy growth rate of 0.5%" is required. This appears to be driven by assumptions included in MISO Future 1. However, this portion has been proposed for removal because of the following reasons:
    - the approximate 0.5% energy and demand growth rates assumed in MISO Future 1 may not be applicable on a regional basis (i.e. specific to Michigan);
    - it is unclear if this load growth would include or exclude energy avoided through energy waste reduction efforts;
    - this line is unnecessary, as load growth resulting from EV adoption is later defined as its own bullet point and therefore, should be handled separately instead of dictating overall load growth rates;
    - a 0.5% annual growth rate may be quite high compared to current utility load growth rates when EWR efforts are accounted for; and
    - an explicit annual growth rate requirement would result in an overly complicated iterative process, specifically, assumptions around EV and electrification goals will be balanced with EWR goals but forcing an end-point solution of 0.5% annual growth rates could conflict with either of those goals.

e. Scenario 1 further clarifies assumptions for EV adoption and customer electrification rates. The requirements of 3-years of historical levels, blended for 2 years and consistent with MISO Future 1 has been proposed for removal. In its place, the Company proposes that utility assumptions for EV adoption and customer electrification rates must be at Electrification Growth rates consistent with MISO Future 1, or higher (by year 5 of the planning horizon).

f. The requirement for **footprint wide** demand and energy growth rates related to EV adoption and customer electrification have been proposed for removal. The Company does not support this requirement on regional load forecast development. Adjusting regional demand forecasts is a highly complex undertaking.

g. The Company proposes to remove the reference in Scenario 1 specific to industrial load increases as a result of low natural gas prices. The industrial load and low natural gas prices haven't shown close correlation and is not a necessary element of the sensitivity.

h. The Scenario 1 high load growth sensitivity is proposed to be removed. Instead, a high load growth sensitivity is proposed for Scenario 1 that evaluates the high load growth assumed in Scenario 2. Because Scenario 2 assumes "electrification drives a total energy growth by 2040 that is consistent with the most recent MISO Future 3", which currently results in a 1.71% compounded annual growth rate (CAGR) on energy and a 1.41% CAGR on demand, we believe it is reasonable to reduce the number of load forecasts required, and rely on MISO Future 3 to drive the assumptions for high load growth in this sensitivity (which is approximately 1.5% growth).

i. Further clarification and definition are requested for the transmission congestion sensitivities proposed in both scenarios. The items below represent the Company's suggestions at this time, however those suggestions may change as more clarity is gained on this sensitivity.
    a. Specifically, is this sensitivity designed to evaluate the impact of congestion on the locational marginal price? Or is this sensitivity designed to evaluate the impact of the cost of energy purchased from outside the state of Michigan? We assume the latter. If correct, we understand this to mean a cost adder would be applied to all energy imported to Michigan from out-of-state. However, there are many questions about what cost adder is appropriate.
    b. Further, we believe that a different percentage increase would apply in Scenario 1 versus Scenario 2.
    c. Lastly, clarification is needed on the basis on which to apply a percent increase. What is the starting point? Also, is the same percent increase applied to all hours of all years of the study period?
    d. Would it make more sense to assume a percent increase, or an explicit $/MWh cost adder?

j. The Company does not support requirements in Scenario 2 requiring minimum penetrations of wind and solar to be consistent with the MISO Future 3. The resource expansion plans should be an output of the economic resource selection modeling and not a required input. Carbon reduction targets, renewable energy costs, demand side management program costs, load growth and other scenario assumptions should determine the resource expansion plans – **not** the expansion plans determined by MISO Future 3.

    a. In lieu of this statement, we have proposed an alternative, which requires that the overall energy served is met through a **combination** of renewables and demand side management resources – but is not explicitly requiring levels of wind and solar installation.

k. Scenario 1, Base Case, explicitly requires a 63% reduction in carbon, however Scenario 2, Electrification and Decarbonization scenario intended to reflect a highly decarbonized and electrified future does not have a carbon reduction target. The Company proposes an 80% carbon reduction target by 2040 consistent with MISO Future 3 assumptions yet provides a target year similar to the end point year of past IRPs filed by Michigan utilities.

l. Scenario 2 contemplates reductions in the cost of renewable and storage resources: however, no scenarios or sensitivities include reduction in demand-side management (DSM) program costs. While we do not necessarily suggest that DSM costs are likely to decline, by not including a cost reduction, the scenario is likely to bias renewable energy resources over DSM resources, which could result in Proposed Resource Plans with lower levels of DSM, as those resources will likely be seen as less economic across more scenarios and sensitivities.

m. With regards to the updated EWR/DR potential studies, it is important to note that adjustments may still have to be made by the utility in order to break out the utility specific portion of these studies for the purposes of future IRP filings. The breakout available for the Guidehouse MPSC potential study will provide a **rough approximation** for Consumers Energy's territory, as Guidehouse's approach aggregated all Lower Peninsula energy efficiency and demand response potential into single overall "buckets." Therefore, Guidehouse will estimate Consumers Energy's potential based on Consumers Energy's overall percentage share of customers and usage in the Lower Peninsula but may not capture differences between different utility service territories. Utility specific projections and data will also continue to be evaluated regarding DR and EWR potential in Consumers Energy's service territory.

2. Please provide any feedback supporting or suggesting changes to Staff's proposed Filing Requirements.

Please reference the attached Draft IRP Filing Requirement redline document for feedback and recommended updates.

In conjunction with the provided redline, Consumers Energy would like to expand on the following feedback:

a. The Company is supportive of the shift to requiring elements of the filing requirements be included in the IRP filing of testimony and exhibits as opposed to a separate report, as this will streamline the filing as well as reduce the amount of documentation that is created by the utility and reviewed by Staff and stakeholders.

b. With regard to the requirement to provide procurement information and alignment with the most recent Commission approved Competitive Procurement Guidelines, the Company suggests as much flexibility as possible and has recommended a change from procurement strategy to procurement process. Procurement processes and strategies can change over time, and there could be situations in the future where procurement could occur before or during an IRP or

Consumers Energy
1945 W Parnall Rd
Jackson, MI 49201

800-477-5050
ConsumersEnergy.com

could instead amend an existing contract and seek approval through the IRP. This filing requirement has been adjusted to require a description of the planned procurement process more generally.

c. The Company does not agree with the breakout of demand response and distributed generation programs from energy waste reduction. Both energy efficiency and demand response fall under the category of energy waste reduction and therefore they should be treated similarly in the filing requirements of IRPs. The current proposed breakout creates redundant requests of the same information for EE, DR, and DG programs.

d. The Company has removed filing requirement items that do not provide value to the filing or to Staff/stakeholder review, such as the amount of spot market purchases and off-system sales.

e. Net present value of revenue requirements has been updated to reflect "incremental" NPVRR in all instances. The revenue requirement for existing generation is approved in rate cases, and so it is more appropriate to call out incremental NPVRR for IRPs.

f. With regards to the new item added under transmission analysis regarding transmission systems benefits of interconnected storage, the Company is interested in further discussions regarding the specific filing requirements in this area and the elements that analysis should include. If transmission benefits of storage are to be included in IRP filings, there are several concerns with how this item is currently written.
    a. The utility may not be the expert on transmission system benefits with transmission interconnected storage, and the analysis may be better served by an outside party or transmission provider.
    b. The siting of storage resources is not determined through the IRP. Without identifying specific locations for transmission-connected battery resources, this requirement may only be able to be met through qualitative statements.
    c. Transmission system benefits of storage may already be met through the requirement to model short- and long-term duration storage prototypes, therefore transmission system benefits can be incorporated into modeling of storage prototypes as opposed toa separate element of transmission analysis.

g. Company responses to the updated Environmental Considerations and Environmental Justice filing requirements have been incorporated into the attached redline for ease of matching comments with the specific line item. As mentioned in the December 16th stakeholder session, the Company is open to a more detailed sub-group that will work to continue to discuss and refine environmental and environmental justice requirements throughout this process.

3. Are stakeholders generally supportive of the two MIRPP scenarios for all rate regulated utilities?

In general, the Company is supportive of reducing the number of scenarios required in the MIRPP from three scenarios to two. It is key that the Base scenario differ significantly from the second defined scenario in terms of assumptions in order to allow for a more valuable comparison of potential futures in utility planning and understand the different impacts associated with different assumptions.

As the key elements of the current draft Electrification and Decarbonization scenario are centered around carbon reduction, it may be more appropriate to simplify the terminology associated with this scenario to just the Decarbonization scenario; while electrification can be a key element associated with decarbonization targets, other considerations in IRP planning can also apply that are not specifically called out in the name of this scenario.

As discussed in the response to Question 1, while the Company is generally supportive of two scenarios, continued discussion and clarification is needed on these two specific MIRPP scenarios regarding alignment with the MISO Futures process and how rate regulated utilities model an IRP for their service territory using this information.

4. Do Stakeholders feel that the Electrification and Decarbonization scenario would adequately take the place of the two additional runs directed by the Commission in the February order in U-20633?

In general, the Company agrees that the requirements of the Electrification and Decarbonization scenario are an appropriate replacement of initial, additional modeling requirements defined in the U-20633 order. As defined, the load growth and carbon reduction parameters defined in the draft Electrification and Decarbonization scenario are sufficient to replace what was defined in the previous order. As discussed in the responses to questions 1-3 and in the comments and redlines provided in the draft IRP Filing Requirements and draft MIRPP documents, Consumers Energy has provided initial feedback and suggestions to further build out the scenario and sensitivities that would take the place of model runs defined in order U-20633.

5. Considering ED 2020-10 and other carbon goals, how do we more accurately count GHGs without double counting purchases and sales between utilities within Michigan?

Properly accounting for the carbon associated with electric generation is a crucial component of accurately quantifying GHG emissions. There are three main generation categories from which we serve our customers load: owned generation, bilateral Power Purchase Agreements (PPAs), and purchases from the MISO. There are times when our energy requirements are low, and we are selling excess generation into the MISO market. Conversely, there are times when our energy requirements are high, and we need to purchase from the MISO market.

To properly understand the various accounting options and methodologies the Company worked with the Electric Power Research Institute (EPRI) to develop five different carbon accounting approaches.

EPRI identified and described five approaches that can be used by electric companies to address the GHG emissions embedded in wholesale power purchased for resale to end-use customers. These options include:

- A source-based approach - accounts for GHG emissions of owned and operated facilities, but excludes emissions associated with power purchases.
- A simplified portfolio approach - accounts for GHG emissions of owned and operated resources, as well as emissions associated with net wholesale electricity purchased, using a system average emission rate for both bilateral power purchase agreements and purchases from the energy spot market.
- A specified portfolio approach that accounts for GHG emissions of owned and operated resources, and any specified wholesale electricity procurement, plus emissions associated with bilateral power purchase agreements, and purchases from the energy spot market using a system average emission rate.
- An annual net-short approach that accounts for the GHG emissions associated with owned and operated non-dispatchable resources, plus emissions associated with non-dispatchable bilateral power purchase agreements. All remaining energy requirements used to serve load are assigned a residual system emission rate (equivalent of a new natural gas fired unit).
- An hourly net-short approach that is similar to the annual net-short approach but utilizes hourly residual emission rates.

More information about these methodologies can be found on EPRI's webpage here: https://www.epri.com/research/products/3002015044.

The specified portfolio method was selected by the Company to account for the carbon that is generated from all sources used to serve customer load. The Company felt this methodology was the most accurate and thus provided better information to base emissions-related decisions on. A more detailed rationale is found in our latest Integrated Resource Plan filing (U-21090) in the direct testimony of Heather Breining.

In an IRP, double counting could potentially occur if the Company's MISO purchases and sales were not netted. The methodologies described above do net MISO purchases and sales, and so this concern is not realized.

It is worth noting, however, summing the emissions estimates calculated in an IRP across all utilities in the State would not result in an accurate representation of the State's total emissions; each utility may be calculating their emissions using different assumptions.

Respectfully submitted,

Consumers Energy Company

Consumers Energy
1945 W Parnall Rd
Jackson, MI 49201

800-477-5050
ConsumersEnergy.com

Application Instructions for Integrated Resource Plan Filings

These application instructions apply to a standard electric utility application for Michigan Public Service Commission (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, 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 a 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

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[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.

considered withdrawn. If a certificate of necessity (CON) is also being filed, the same filing announcement would serve as the filing announcement 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; and
d) Information related to any CON application that would be filed with the utility's IRP.

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 with 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 proposals (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 with the IRP application documentation demonstrating that the RFP process was completed;
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, and Commission rules;

d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, 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 purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Stakeholder 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; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

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 the 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. Documentation may 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; and

f) Discussion indicating if or how the public outreach process influenced the IRP.

A minimum of two stakeholder engagement workshops are recommended. A stakeholder engagement workshop will provide stakeholders with 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 invite stakeholders, including expected intervenors and the Staff, to its stakeholder engagement workshops.

If the stakeholder engagement workshops are not open to the public, two additional public meetings are recommended. 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 public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advanced notice provided to customers in the utility's service territory. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

If the utility chooses to hold pre-filing workshops, including stakeholder 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 should be maintained on a website in a location open to the public for the duration of the stakeholder 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 analysis of the ~~preferred plan~~ **proposed resource plan** and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the **proposed resource plan** ~~preferred plan~~ and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies for each scenario to determine how each strategy would perform in an unexpected range of possible futures. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis 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.

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.

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 facilities, 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:

I) For specific supply-side resources (inclusive of storage technologies such as battery storage) of less than 225 megawatt (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators, storage facilities, etc.), that are planned to go into service 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:

i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;

ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and iii. Annual depreciation on the capital investment.

b) Projected annual return and income taxes on capital investment.

c) **Projected fuel costs over the life of the facility in current dollars per kilowatt-hour (kWh).**

d) 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.

e) Projected property taxes;

f) The rates of escalation of cost, including:

i. Capital costs;

ii. O&M costs which are variable and related to fuel;

iii. O&M costs which are variable and unrelated to fuel; and

iv. 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, **and** 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) **A description of the planned procurement ~~strategy~~process, ~~including power purchase agreements and company owned.~~ Reference the most recent Commission approved Competitive Procurement Guidelines.**

o) **A general description of the potential decommissioning process, costs, and ~~how the utility intends to provide assurance of proper~~ disposal ~~with consideration of material salvage and recycling.~~**

Commented [A1]: Company Response - While an IRP can provide general decommissioning information as part of its filing, a depreciation case is a more appropriate place to include the details listed in this item. The assets requested for cost of approval can have a 25 to 35-year life, making decommissioning process and costs highly speculative at the time of filing. Recommend removing this requirement or changing the language to the proposed edits.

II) Renewable Resources: The utility shall file data consistent with its renewable energy plan. (For incremental renewable energy beyond the 15% requirement in 2021 and any renewable energy to be constructed or purchased after the conclusion of the 20-year renewable planning period ending in 2029, the utility shall file as set forth below.) Revenue requirement and incremental costs of compliance shall be calculated to include the following:

a) Capital, operating and maintenance 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) Ancillary service costs.

e) Cost of purchased renewable energy credits (RECs) other than those purchased for noncompliance.

f) Cost of Contracts.

g) Expenses incurred as a result of governmental action including changes in tax or other laws.

h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.

i) 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); and

j) Provide the following information in relation to renewable resource cost recovery:

   i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and

   ii. Forecast through the end of the renewable plan period of the regulatory liability balance.

k) **A description of the planned procurement ~~strategy~~ process, Reference the most recent Commission approved Competitive Procurement Guidelines.**

l) **A general description of the potential decommissioning process, costs, and disposal.**

~~l)~~m) ~~**Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.**~~

~~m)~~n) ~~**A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper**~~

Commented [A2]: Company Response - While an IRP can provide general decommissioning information as part of its filing, a depreciation case is a more appropriate place to include the details listed in this item. The assets requested for cost of approval can have a 25 to 35-year life, making decommissioning process and costs highly speculative at the time of filing. Recommend removing this requirement, or changing the language to the proposed edits.

~~**disposal with consideration of material salvage and recycling.**~~

III) Energy Waste Reduction: The utility shall provide the following information in relation to ~~demand response programs,~~ energy waste reduction programs~~, and distributed generation programs~~ cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:

i. Annual O&M cost for each individual portfolio of energy waste reduction~~, demand response~~, and distributed generation programs;

ii. Annual capital cost for each individual portfolio of energy waste reduction~~, demand response, and distributed generation programs~~; and

iii. 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;

c) Maximum single event demand reduction;

d) Total resource capacity (MW) and type ~~(load modifying resource, emergency demand response, etc.)~~ reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);

e) Total energy reduction achieved (megawatt-hours (MWh)); and

f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) **Demand Response and Distributed Generation Programs: The utility shall provide the following information in relation to demand response programs~~, energy waste reduction programs,~~ and distributed generation programs cost approval and**

Commented [A3]: Company Response – the company does not believe this breakout is necessary. DR and DG can have cost approval structures similar to EWR, as a group of programs or a portfolio, and therefore should be treated equally

recovery. For each individual program or group of programs, provide:

a) Total annual cost including:

i. **Annual O&M cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs;**

ii. **Annual capital cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs; and**

iii. **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;**

c) **Maximum single event demand reduction;**

d) **Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);**

e) **Total energy reduction achieved (megawatt-hours (MWh)); and**

f) **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 ten 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 ~~Report 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~~ **proposed resource plan** ~~preferred resource plan~~ and resource acquisition strategy**, if approved,** and signed by an officer of the utility having the authority to commit the utility to the resource acquisition **approach** ~~strategy~~, acknowledging that the utility reserves the right to make changes to its resource acquisition ~~strategies~~ **approaches** 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** ~~preferred resource plan~~ and resource acquisition **approach** ~~strategy~~;

c) The data and information requested in the Commission's IRP filing requirements included herein; and

d) Any other information deemed relevant by the utility.

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

I) Executive Summary:

An IRP shall include an executive summary, suitable for distribution to the public. The executive summary shall be an informative nontechnical description of the **resource plan proposed by the utility** ~~preferred resource plan~~ 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; and

b) A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the goal to be achieved by its proposed course of action and implementation strategy.

II) Table of Contents: Shall be provided **for the contents of the filed case as a filed exhibit that includes witness~~,~~ and witness topic and section(s).**

III) ~~Table of Figures: Shall be provided~~ ~~**for the contents of the filed case.**~~

Commented [A4]: Company Response – a specific listing of figures is not necessary as figures are accounted for in the filing of testimony and exhibits

IV) 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:

   i. Net present value of utility revenue requirements,[2][1] with and without any financial performance incentives for demand-side resources;

   ii. ~~Revenue requirement of existing generation and power purchase agreements;~~

   iii. Summary of existing generation and power purchase agreements by fuel type;

   iv. Utility's existing capacity resource mix;

   v. Utility's service territory and breakdown of customer class composition; and

   vi. Description of planning period analyzed;

b) Statement of power need;

c) Identify **the witness or witnesses that describe the source and basis for key forecasts such as** ~~and explain the basis for the~~ forecasted price of energy, capacity, and fuels, ~~and of~~ peak demand and energy requirements, for~~each year of~~ the analysis 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:

Commented [A5]: Company Response - Revenue requirement for existing generation is approved in rates cases, and is not incremental to long term revenue requirements. PPA costs are accounted for in the net present value of revenue requirements.

[1] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Results should be presented in nominal dollars

i. RTO market and state regulation structure if a multistate utility;

ii. Potential changes to RTO capacity market

iii. ;iii. Electric customer choice;

~~ii.~~iv. iv. Transmission expansion;

v. Environmental;

vi. Renewable portfolio standards; and

~~vi.~~vii. vii. Other;

e) IRP planning process; and

f) Stakeholder report.

V) Analytical Approach:

a) Describe the modeling process, including the duration of the study;

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

i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various ~~preferred~~ resource plan options;

ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan;

iii. 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.

c) 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 ~~preferred~~ 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.

d) **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, for the proposed resource plan and any alternative resource plans presented by the utility.**

Commented [A6]: Clarification Request – is this statement focused on build plan comparisons against each other with regards to risk, or is it focused on a requirement to include each of these build plans in a risk analysis of the selected risk variable(s)? Or both?

VI) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities;

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-**XXXXX**, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VII) Existing Supply-Side (Generation) 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) Power purchase agreements: energy and capacity purchased

or produced by the utility from a contracted resource, including any cogeneration resource;

h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.);

i) ~~Spot market purchases and off-system sales.~~

VIII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:

i. Description of current demand response 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;

ii. **Historic performance of existing demand-side programs and how the utility used such information in its demand response resource decisions;**

iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response;

iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

IX) Renewables and Renewable Portfolio Standards Goals: 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 renewable energy credit 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 goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
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.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period;
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio;
    ii. Forecast RECs obtained via Michigan incentive RECs; iii. Forecast expected compliance levels by year to meet the

renewable portfolio targets; iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio;

v. Identify risks which may drive performance to vary.

X) 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 energy waste reduction 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, and the actions the utility proposes to take in order to achieve that peak demand reduction;
b) Subsections:
    i. Key variables used to develop forecast; ii. Long-term forecasting methodology; iii. Forecasting uncertainty and risks;
    iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers);
    v. **Base Case** ~~Business as usual~~ deliveries and demand forecast;
    vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. **U-XXXXX**, or subsequent Commission orders relating to IRP modeling parameters and requirements.
    vii. **Include detailed information about how the forecasts used for IRP modeling align with forecasts used for distribution planning.**
    viii. **Detail information about distributed energy resource adoption and operation, including distribution connected generation and storage.**

ix. **Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.**

x. **Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.**

XI) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. 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 foreach facility in the portfolio.

XII) Transmission Analysis:

In accordance with MCL 460.6t(5)(h), the utility shall 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 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;
b) **Include an analysis of any transmission system benefits associated with transmission interconnected storage**
c) A detailed description of the utility's efforts to engage local transmission owners ~~in~~ **throughout** the utility's IRP process. ~~**In an effort to inform the IRP process and assumptions, a meeting schedule should be set in advance.**~~ The filing should **include** ~~**the pre-decided**~~ **meeting schedules**, ~~**any documentation that**~~

~~**supports requested extensions of the initial pre-decided timing,**~~ **and** ~~including~~ a summary of meetings that ~~**ultimately**~~ **took** place **throughout the process**;

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) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;

Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements 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) **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 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 that support the resource plan proposed by the utility.**

i) **Include an analysis of transmission costs for access to out of state resources conducted by either the RTO, transmission owner(s), and/or utility.**

j) **Provide RTO reports or web links to report locations that contain information relied upon to support model assumptions or other IRP decisions.**

Commented [A7]: Company Response – the studies indicated may not always be available. Just because the capabilities can be increased does not mean that those increases are justified. Projects need to be justified by MISO's Tariff, NERC TPL Requirements, or State requirements.

Commented [A8]: Company Response – outside of a transfer analysis performed by the local transmission owner showing whether or not there are impacts on CIL, specific siting assumptions would have to be assigned to the resource plan

Commented [A9]: Clarification Request – With regards to "information relied upon to support model assumption" – is this specifically referencing transmission specific model assumptions, or is this designed to be more broad?

XIII) 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; and
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.

XIV) 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 ~~generation~~ resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. 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 of each resource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned **resources** ~~generation~~;
b) New build:
    i. New generation technology and operating assumptions; ii. New generation development costs; iii. New energy integration of storage technology and operating assumptions, **including both long and short duration storage**;
    iv. New energy storage development costs;
    v. ~~**Development costs and operating assumptions for combinations of resources constructed as a single facility.**~~
c) Distributed generation:
    i. Solar photovoltaic (including solar plus storage);ii. Biogas; iii. Energy storage; iv. Other distributed generation;
d) Market capacity purchases:
    i. Regional market supply outlook; ii. Availability of market capacity; iii. Market capacity price assumptions;
e) Long-term power purchase agreements;
f) Transmission resources:
    i. Overview;
    ii. Existing import and export capability;
    iii. Transmission network upgrade assumptions for the IRP; and
    iv. Import and export impact on resource strategy.

XV) 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 necessarily exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination);

b) ~~Scenario and sensitivity~~ Results **for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that** include annual revenue requirements, 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;

c) ~~Business as usual/reference~~ **Base** case_**optimization** ~~portfolios~~ **portfolios utilized**~~options to be selected from~~;

d) Analysis of IRP results; and

e) Risk assessment **presented with graphics and data that illustrate stochastic risk analysis results in such a way that the probability distributions are clearly conveyed 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.**

XVI) **Proposed Resource Plan**: Include a detailed description of:

a) The type of energy resource 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 power purchase agreements;
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 proposed course of action.

The utility shall describe the process used to select the **proposed resource plan** ~~preferred 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 ~~preferred resource plan~~ **proposed resource plan** satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified;
b) Utilize renewable, **storage** and demand-side resources to comply with existing laws and goals and, in the judgment of the utility, are consistent with the public interest and achieve state energy policies; and
c) In the judgment of the utility, the **proposed resource plan** ~~preferred plan~~, in conjunction with the deployment of demand response measures, has sufficient resources to serve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the **proposed resource plan** ~~preferred 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**n incremental** net present value revenue requirement 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 net present value revenue requirement of the utility's proposed **resource** plan and **any** alternative resource plans including the alternative resource plans resulting from the Commission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.
e) **A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning such as distributed energy resources 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.**
f) **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.**
g) **A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.**

XVII) Rate Impact and Financial Information:

Projected year-on-year **incremental** impact of the proposed **resource plan** ~~course of action~~ (and other feasible options) for the periods covered by the plan, covering the following accounts:

a) Revenue requirement;
b) Rate base;
c) Plant-in-service capital accounts;
d) Non-fuel, fixed operations and maintenance accounts;
e) Non-fuel, variable operations and maintenance accounts;
f) Fuel accounts;
g) Emissions cost;
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

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 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) **Incremental n**~~N~~et present value of revenue requirements for the plan;
g) Nominal revenue requirements by year; and
h) Average system rates per kWh by year.

XVIII) Environmental **Considerations and Environmental Justice**:

Describe how the utility's **resource plan and any alternative**

resource plans presented in the application ~~proposed IRP~~ 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) **If the Company is proposing retirement of an existing resource, clearly identify the capital cost for any final or proposed environmental regulations and other capital or operating & maintenance (O&M) investments in the facility that is either avoided ~~capital~~ cost or ~~the~~ cost of removal~~, becomes cost of removal, or is truly avoidable cost.~~**

d) ~~Provide an annual projection of the following emissions for the study period differentiating between existing and new resources within the proposed IRP:~~

~~i. Tons of sulfur oxides; ii. Tons of oxides of nitrogen; iii. Tons of carbon dioxide; iv. Tons of particulate matter; and~~

~~v. Pounds of mercury.~~

e) ~~Provide the total projected emissions of the items listed below through the study period for the utility's proposed plan, as well as the scenarios identified in the MIRPP as approved in Case No. U-18418, or modified by Commission order:~~

~~i. Tons of sulfur oxides; ii. Tons of oxides of nitrogen; iii. Tons of carbon dioxide; iv. Tons of particulate matter; and~~

~~v. Pounds of mercury.~~

f) **Hold a technical conference with MPSC and EGLE staff within 30 business days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.**

g) **Identify, quantify, and provide testimony that compares the expected changes in criteria pollutants, mercury, VOCs, and GHG emissions of the proposed resource plan in the base case to the previously approved build plan in the base case. Illustrate how the proposed resource plan will comply with state and federal GHG goals.[2],[3] The previously approved build plan may include a refresh that takes into account the updated load forecast and additional resources to meet any increase in load, but leave the previous base generation assumptions in place. The Company will use a proxy to determine the emissions from MISO purchases and will run the base case scenario with two build plans: the previously approved base build plan and the proposed resource plan.**

h) **Analyze multiple build plans, including the proposed resource plan and the optimal build plan from the MIRPP required scenarios to identify and both qualitatively and quantitatively assess the potential impacts to vulnerable communities. This assessment should address water quality, water use, water discharge, waste disposal, air emissions, public health, climate, environmental justice, early retirement, and other considerations that were taken into account in the Company's decision. The Michigan Environmental Justice Screening Tool or equivalent such as the EPA's EJSCREEN tool should be used for the identification of potential vulnerable areas.**

i) **Identify and assess the impact of the proposed resource plan to any non-attainment areas in effect one year prior to the IRP filing deadline within the electric utility service territory and qualitatively support in testimony. Impacts should consider SO_2 and ozone, as well as their precursors NO_x and $PM_{2.5}$.**

j) **Using the areas identified as vulnerable ~~by~~after utilization of the Michigan Environmental Justice Screening Tool, or equivalent (see h) above) complete a more comprehensive evaluation of PM2.5 impacts to these communities, describing expected air quality impacts, including the effect of an early retirement. Conduct dispersion modeling for PM2.5 using standard permit modeling protocols and methods. The base case emissions should be used to establish a baseline modeling demonstration by which to compare the previously referenced least emitting and potential early retirement scenarios in the area where emissions are expected to occur.**

[2] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) on September 23, 2020, 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.

[3] 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.

Commented [A10]: Company Response - We have concerns with the inclusion of VOCs. There is a lack of data availability for VOCs for non-CE generators, particularly when estimating MISO emissions.

Commented [A11]: Company Response - It is unclear how this language is different from language earlier in this paragraph of "… of the proposed resource plan in the base case to the previously approved build plan in the base case." If it is referring to the same comparison, then it be clearer if it was deleted.

Commented [A12]: Company Response - This is messy on the proposal of comparing a proposed resource plan back to the previously approved build plan. It actually creates another scenario because a utility would need to re-run an old plan from a previous IRP through an updated scenario. Propose instead to compare the base case optimal plan to the proposed plan. The base case optimal plan would incorporate a refresh and would lock in prior resources previously approved. Comparing base case optimal plan with the proposed plan gives you an idea of whether the proposed plan is performing the same or better than the base case plan or status quo. The approach listed here introduces misalignments in comparisons, creating more work to explain why you can't compare the two plans direct and attempting to close the gap through explanation. If the goal is to see if a utility is on track with reducing emissions, then it would be preferable to request a regression line of sorts showing declines that can compare the previous emission reduction projection to a proposed plan. This removes variability in assumptions and meets the overall goal of seeing ongoing performance in mitigating emissions.

Commented [A13]: Company Response – there is not a definition included in this document of what vulnerable communities encompasses - need to define what these are before there is a requirement to assess potential impacts

Commented [A14]: Company Response - We'd like to discuss this language. Here are our initial thoughts:
a) While it addresses many of the right concepts, the current language is very vague.
b) Some of it is duplicative of other fling requirements. For example, the "public health" language seems ...

Commented [A15]: Company Response - A couple of thoughts regarding the tool:

(a) We think that EPA's EJSCREEN should also be listed as acceptable. ...

Commented [A16]: Company Response - Non-attainment areas can change over time, as data evolves, so we have recommended a point in time to make this evaluation. We're recommending a year before the IRP is due to be filed, as this provides enough time to do the evaluation.

Commented [A17]: Company Response – the company does not see value to air dispersion modeling in this context. Even if an IRP projects increasing PM2.5 emissions from historical levels, the air permit itself will likely require dispersion analysis. If it doesn't call for increasing PM2.5 emissions, then this analysis adds little value and would b ...

Commented [A18]: Clarification Request - this language is a little vague, and potentially confusing, can you clarify the intent?

k) **Include metrics to quantify health benefits related to air emission reductions in the scenarios listed above. The following EPA reports and tools provide guidance, which can be selected by the utility as appropriate ~~and are listed in order of preference~~: the Environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the "Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool" and "Quantifying the Emissions and Health Benefits of Energy Efficiency and Renewable Energy".)".**

l) **Identify and~~,~~ quantify ~~and provide evidence in the filing~~ the ~~that shows~~ progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario~~,~~ and the proposed resource plan, ~~and the previously approved plan~~ perform in meeting those goals throughout the planning period.**

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

c) Any modeling input and output files used in developing the application, supporting testimony, **resource plan and any alternative plans** ~~and IRP~~. 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;

d) Cost data, ~~and~~ estimates, and **co-benefit analyses** that were used in the resource screening process **or in any other way to ~~deteriminedetermine~~determine resource selection of** ~~to evaluate~~ each

Commented [A19]: Company Response - We have revised the language to allow the utility to select its preferred tool as appropriate for the situation. For example, if a proposed plan is generally showing reducing emissions through plant closures, it makes little sense to do a data and resource-intensive analysis under the BenMap tool, as an analysis using one of the other tools should be sufficient.

More generally, it would be good to have a demonstration of each tool's pros and cons to the stakeholder group by EGLE. This will allow everyone to understand which tool is most appropriate in different situations.

Commented [A20]: Company Response- as previously stated, the optimized build plan of the base case is the refreshed version of the previously approved IRP under a 5-year pre-approval timeframe. It is unnecessary to conduct an additional run of the previously approved plan (assuming it is the 20 year plan) when the Commission isn't authorized to pre-approve costs beyond a 3-year period, and the IRP statute indicates years of 5, 10 and 15 to be evaluated, with the understanding that IRPs are refreshed at least every 5 years, or sooner if needed.

electric resource that was considered either individually or in combination with other resources **constructed as a single facility**, including **distributed energy resources, storage, and** renewable **energy resources**. ~~alternatives, such as solar, wind, or solar plus battery storage~~;

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

f) 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 proceeding;

g) 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;

h) 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 utilities generation fleet;

i) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP;

j) A comparison of total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the **base** ~~business as usual~~ case;

Commented [A21]: Company Response - These items seem duplicative of the above requirements, so it is unclear why they need to be stated directly here as well.

k) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates;

l) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus battery storage, and such cost estimates for all alternative proposals, solicited or unsolicited, received by the utility;

m) Electricity market forecasts utilized

n) **A stacked bar chart that includes all existing resources and proposed resources color designated by resource type in each of the planning years with the inclusion of a line representing expected load over the length of the planning period.;** and

o) Other documents and data underlying the IRP analysis.

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~~DRAFT~~ Michigan Integrated Resource Planning Parameters for December 16th Stakeholder Meeting

I.

II. Energy Waste Reduction Potential Study

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

The statewide assessment of energy waste reduction (EWR) potential was conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[1]

<u>Scenario #1 - Reference:</u> Estimates of achievable potential calibrated to 2021 total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual achievements. Key assumptions include nonlow income measure incentives of 40% of incremental cost (low income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

<u>Scenario #2 - Aggressive:</u> Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost-effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

<u>Scenario #3 - Carbon Price</u>: Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations. Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

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[1] MI EWR Potential Study, https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Report__Final_735360_7.pdf, Retrieved December 8, 2021.

This EWR potential study has resulted in updated, expanded, and improved information on the Michigan customer base, and the potential for energy and demand reductions possible through EWR programs and initiatives by building upon previous studies, with the addition of natural gas potential and analysis of the Upper Peninsula. While much EWR potential remains, there are unique challenges in Michigan in realizing this potential over the 20-year study period. The potential study incorporates these real factors into the analysis by using primary research findings, Michigan baseline study data, and historical and expected program achievements, to estimate efficient measure and fuel type saturations, as well as calibration targets.

~~The statewide assessment of energy waste reduction (EWR) potential was built upon existing studies provided by two, utility-specific 20-year potential studies conducted in 2016, by GDS Associates, Inc. (GDS). These utility-specific EWR potential studies are considered by MPSC Staff to represent potential values which reflect a base case assessment of achievable, technical and economic potential consistent with requirements of the prior energy law, Public Act 295 of 2008 (PA 295).~~ [2] ~~In determining a statewide assessment, MPSC Staff was cognizant of stakeholder feedback and therefore attempted to consider the Lower Peninsula separately from the Upper Peninsula assessment as discussed below.~~

~~**Lower Peninsula.** In order to develop additional data points which reflect the incremental EWR potential possible under more aggressive program goals consistent with Public Acts 341 and 342 of 2016, stakeholders first combined the separate utility-specific potential studies into a Lower Peninsula study, resulting in an assessment of EWR potential under PA 295 era, base case assumptions. From there, stakeholders developed additional modeling scenarios and sensitivities designed to assess additional cost effective EWR savings available with more aggressive programs.~~

~~The base case assessment and supplemental study results~~[4] ~~were combined into one report and can be found on the energy legislation implementation webpage for the EWR Potential Study.~~[3] ~~This study includes the combined base case potential results on pages 1 through 85, with the additional potential identified under more aggressive EWR programs, summarized starting on page 87. The EWR supply curves for the base case assumptions and more aggressive scenarios are found in Appendix G, starting on page 277 of the report. The modeling scenarios, assumptions, and sensitivities for the supplemental study are briefly summarized below with details provided on the webpage.~~[4]

[2] Public Act 295 Energy Optimization programs contained caps on program spending which were removed in the Public Act 342 Energy Waste Reduction programs.

[3] ~~See supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf~~ **Michigan Energy Waste Reduction Statewide Potential Study (2021-2040) Report submitted by Guidehouse, Inc.: https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Final_Draft_Report_732747_7.pdf**

[4] ~~For more details on the assumptions for the supplemental EWR study for the Lower Peninsula, see http://www.michigan.gov/documents/mpsc/Scenario_assumptions_07.09.17_599440_7.docx.~~ **2021 Energy Waste Reduction and**

~~Scenario #1: Sensitivity on Incentive Levels – GDS revised the basic analysis of Achievable Potential for the Consumers Energy Company and the DTE Electric Company service areas using the assumption that the programs would pay 100% of incremental costs [5] for all measures/bundles of measures that would still pass the Utility Cost Test at the higher incentive level (i.e., if the program's paid incentives equal to 100% of incremental cost of the measure, as opposed to using the 50% of incremental cost assumption.)~~

~~Scenario #2: Aggressive Investment/Emerging Technologies – assumes higher avoided cost for energy and capacity (such as due to higher gas prices), incentives at 100% of the measure's incremental cost, optimistic market penetration, and inclusion of some emerging technologies that are presumed to be cost-effective.~~

~~Scenario #3: Environmental Regulation – assumes environmental regulations have increased electric avoided costs reflecting a monetary value for decreasing carbon emissions.~~

~~**Upper Peninsula.** The Upper Peninsula potential study assessment also built upon the foundation of existing utility-specific potential studies. Efforts were made to incorporate assumptions which reflected the additional opportunities for EWR potential of the Upper Peninsula due to the generally higher cost of electricity in that region.~~

~~The analysis utilized historic and forecast data compiled for the load serving entities in that region for the 20-year period starting in 2016, with estimates for the number of Upper Peninsula region electric customers, sales by sector (i.e., residential, commercial, industrial), and Upper Peninsula region peak load data. The analysis also included background data from existing potential studies from service territories which most closely resembled the rural nature and dispersed populations found in the service territories in the Upper Peninsula.~~

~~The final result of this modest analysis provides a base case estimate of EWR potential under base case assumptions. Additional work would be required to further assess the potential for EWR under the more aggressive modeling scenario/sensitivities.~~

~~**Statewide Assessment of EWR Potential.** The additional assessments for EWR potential for the Lower and Upper Peninsulas for the 2017 through 2036 timeframe were completed in mid-August and together form the basis for the MPSC Staff's statewide assessment of EWR potential. These assessments include supply curves for the Lower Peninsula. As previously mentioned, these studies are available on the MPSC Energy Legislation webpage.~~[7]

III. Demand Response Potential Study[6]

Demand Response Statewide Potential Study portal on the MPSC's website: https://www.michigan.gov/mpsc/0,9535,7-39593308_94792-552726--,00.html.

[5] For Low-Income measures, the utilities are assumed to pay 100% of the measure cost.

[6] ~~See supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf~~ **https://www.michigan.gov/mpsc/0,9535,7-395-93308_94792-552726--,00.html.**

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

The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

~~To comply with Section 6t, Staff determined that the assessment for use of demand response programs would best be comprised of two parts: a technical study[7] and a market assessment.[8]~~

~~**Technical Study.** The technical potential study estimates the technical and achievable potential for reducing on-peak electricity usage through demand response programs for all customer classes. The study determines demand response potential for the 20-year period beginning in 2018.~~

~~In the technical study, demand response potential is calculated using data and assumptions for inputs such as customer eligibility, likely participation rates, per customer demand reduction, program costs, avoided costs, etc. This quantitative measure of demand response potential and~~

[7] ~~Demand Response Potential Study, http://www.michigan.gov/documents/mpsc/State_of_Michigan__Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf.~~

[8] ~~Demand Response Market Assessment, http://www.michigan.gov/documents/mpsc/MI_Demand_Response_Market_Assessment_20170929_602432_7.pdf.~~

~~the costs and savings associated with potential resources have been used as an input for the IRP modeling scenarios.~~

~~Demand response programs considered by the study include behavioral programs, time-of-use pricing, direct load control, interruptible and curtailment, ancillary service, and more. Programs are modeled by customer class. Pre-existing demand response programs were not favored over not-yet-existing programs in the calculation of statewide potential.~~

~~The study results in two levels of realistically achievable amounts of demand response potential, called the integrated low case and integrated high case. The low case is the product of more conservative assumptions for program participation and enabling technology penetration, while the high case assumes higher participation. For example, the low case assumes residential time-of-use rates are opt-in for customers, resulting in lower participation than the high case, where time-of-use rates are opt-out. Full details on all of the assumptions relied upon are described in the study.~~

~~**Market Assessment.** The market assessment examines the potential for demand response for large commercial and industrial (LCI) customers through surveys, interviews, and analysis of the customer class. This approach evaluates the LCI customer's capability, desire, and motivation to participate in demand response programs by gathering that information directly from those customers to determine interest and capability for participating in demand response programs, identifying any barriers to participation, and evaluating a reasonable and achievable potential for peak load management in Michigan.~~

~~LCI customers are defined as non-residential, non-lighting customers that have a maximum annual demand of greater than or equal to 1 MW. Given the wide diversity of load profiles in the LCI class and the constrained timeline for the market assessment, it was best to focus on the largest (by demand) customers first. Also, LCI customers represent a large portion of statewide load and have shown to be highly receptive to demand response programs.~~

~~By surveying LCI customers to determine the parameters of a demand response program that would maximize their participation, the market assessment provides better insight on customers' energy needs to inform effective program design and better inform the statewide assessment.~~

~~When combined into a comprehensive statewide assessment of demand response potential, the results of the two studies provide demand response resources, with cost and megawatt load reduction per program that can compete directly with supply-side options in the IRP modeling process. The IRP model will choose the most economical way to meet load, whether the resource increases supply or decreases demand. The potential study provides the data necessary, including the limits of the demand side resources, to allow all methods to meet load to compete equally.~~

~~**Study and Stakeholder Process.** MPSC Staff met with the demand response workgroup in March and April to develop scopes for the two-part study. After combining the ideas and comments of stakeholders in the workgroup, MPSC Staff issued requests for proposals in May.~~

~~Bids were received and evaluated in June, and contracts for the two studies were awarded. Three Stakeholder meetings were held during the study to provide updates and receive feedback. The contractors delivered the final statewide potential study on 29, 2017~~. ~~The final study integrates results of the market assessment.~~

IV. 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.

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

Federal rules and laws:

Clean Air Act – The Clean Air Act is a United States federal law designed to control air pollution on a national level. The Clean Air Act 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 Clean Air Act 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. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standards are set at a level that is protective of 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 pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[9]

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, forward progress in controlling emissions within their boundaries. Those that do not abide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject to **US**EPA 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 **US**EPA for approval into the State Implementation Plan, 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.

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

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

A federal consent order set deadlines for the **US**EPA to designate nonattainment areas in several rounds. Round one designations were made in October 2013, based on violations of the NAAQS at ambient monitors. A portion of Wayne County was designated non-attainment. T~~he area must attain the NAAQS by October 2018. The state's attainment plan was due to theE PA by April 2015~~.

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into compliance with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan for the non-attainment area, the action of which is still underway.

Round two designations were based on modeling of emissions from sources emitting over 2000 tons of SO_2 per year. A portion of St. Clair County was designated nonattainment in September 2016. ~~Attainment must be achieved by September 2021, and the state's attainment plan is due to the EPA by March 2018~~.

To better understand the quality of the air in the non-attainment area, two~~ew~~ monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020~~1~~, waiving the SIP requirement for the area. Upon shutdown of the St. Clair Power Plant in 2022~~2~~, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations **were to** ~~ill~~ address all remaining undesignated areas by December 31, 2017. The **US**EPA 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 **US**EPA 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**~~ intended to also be~~ designated as unclassifiable/attainment.

Ozone Non-Attainment 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 non-attainment 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[10] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also more stringent requirements for major source air permits, including lowest achievable emission rate conditions and offsets for new emissions of the ozone precursors of nitrogen oxides and volatile organic compounds. To attain the standard, monitoring values over the three-year time period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

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 Clean Air Act for the ozone standards and fine particulate matter standards. CSAPR is a cap and trade rule which governs the emission of SO_2 and NO_x from fossil-fueled electric generating units through an allowance- based program. Under this program, NO_x is regulated on both an annual basis and during the ozone season (~~May~~ **April** through **October** ~~September~~). Each allowance (annual or ozone) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. ~~Recently,~~ The **US**EPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. ~~In the future,~~ The state ~~will have~~ **currently has** Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the Revised CSAPR rule update for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the rule required additional emissions reductions of NO_x from power plants in 12 states, including Michigan.

EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the **US**EPA to adopt maximum available control technology standards for hazardous air pollutants. 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. Existing sources were required to comply with these standards by April 16, 2015. Some individual sources were granted an additional year, at the discretion of the Air Quality Division of **EGLE** ~~the MDEQ~~. In June 2015, the United States Supreme Court found that the **US**EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the **District of Columbia** Circuit Court of Appeals ruled that MATS may be enforced as the **US**EPA modifies the rule to

[10] The designe value is the three year average of the 4th highest 8-hour ozone value)

comply with the United States Supreme Court decision. The deadline for MATS compliance for all electric generating units was April 16, 2016.

In May 2020, USEPA corrected flaws in the 2016 Supplemental Costs Finding for the MATS rule consistent with the 2015 United States Supreme Court decision. The agency also completed the CAA required residual risk and technology review (RTR) for MATS. Power plants are already complying with the standards that limit emissions of mercury and other hazardous air pollutants (HAPs), and this final action leaves those emission limits in place and unchanged.

Clean Air Act 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 Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the **US**EPA finalized a NSPS that established standards for emissions of carbon dioxide for newly constructed, modified, and reconstructed fossil-fuel fired electric generating units. There are different standards of performance for fossil fuel-fired steam generating units
and fossil fuel-fired combustion turbines.[11]

Clean Air Act Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the Clean Air Act requires the **US**EPA to establish standards for certain existing industrial sources. The final Clean Power Plan, promulgated on October 23, 2015, addressed carbon emissions from electric generating units. The Clean Power Plan established interim and final statewide goals and tasked states with developing and implementing plans for meeting the goals. Michigan's final goal was to reduce carbon dioxide emissions by 31 percent from a 2005 baseline by 2030.[12]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay of the Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the **US**EPA to review the Clean Power Plan and the standards of performance for new, modified, and reconstructed electric generating units (section 111(b) rule). As a result, the Department of Justice filed motions to hold those cases in abeyance pending the **US**EPA's review of both rules, including through the conclusion of any rulemaking process that results from that review. ~~The Clean Power Plan does not currently affect Michigan utilities, however due to the EPA's 2009 endangerment finding on greenhouse gases, utilities should address their future anticipated greenhouse gas emissions~~.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated

[11] The 111(b) standards can be found in Table 1 here: https://www.federalregister.gov/documents/2015/10/23/2015-22837/standards-ofperformance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary.
[12] The 111(d) rule can be viewed in full here: https://www.federalregister.gov/documents/2015/10/23/2015-22842/carbon-pollutionemission-guidelines-for-existing-stationary-sources-electric-utility-generating.

the ACE rule and remanded it back to the USEPA for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West Veirginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer

2022.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current goals on carbon neutrality at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon neutrality goals in mind.

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 carbon dioxide underground. Facilities calculate their emissions using approved methodologies and report the data to the **US**EPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The **US**EPA conducts a multi-step verification process to ensure reported data is accurate, complete and consistent. This data is made available to the public in October of each year through several data portals.

Boiler Maximum Achievable Control Technology – The Boiler MACT establishes national emission standards for hazardous air pollutants 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 Clean Air Act 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. 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, nitrogen oxides, sulfur dioxide, 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. A BART analysis considered five factors as part of each source-specific analysis: 1) the costs of compliance, 2) the energy and non-air quality environmental impacts of compliance, 3) any existing pollution control technology in use at the source, 4) the remaining useful life of the source, and 5) the degree of visibility improvement that may reasonably be anticipated to result from use of such technology. For fossil-fueled electric generating plants with a total generating capacity in excess of 750 MW, states must use guidelines promulgated by the **US**EPA. In 2005, the **US**EPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the **US**EPA issued a final rule setting revised and clarifying requirements for periodic updates in state plans. The next periodic update **was** ~~is~~ due July 31, 2021. **EGLE has submitted the periodic update and it is currently being reviewed by USEPA.** There are two Class 1 areas in Michigan: Seney National Wildlife Refuge and Isle Royal National Park. Michigan also has an obligation to eliminate the state's contribution to impairment in Class 1 areas in other states.

Resource Conservation and Recovery Act – The Resource Conservation and Recovery Act (RCRA) gives the **US**EPA the authority to control hazardous waste from the "cradle-tograve", 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.

In April 2015, the **US**EPA established requirements for the safe disposal of coal combustion residuals **(CCR)** produced at electric utilities and independent power producers. These requirements were established under Subtitle D of RCRA and apply to coal combustion residual landfills and surface impoundments. Michigan electric utilities must comply with these regulations.

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 **US**EPA 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 twenty-five percent of the water withdrawn from the surface waters of the United States for cooling purposes.

In 2001, the **US**EPA promulgated rules specific to cooling water intake structures at new facilities. Generally, new Greenfield, stand-alone facilities are required to construct the facility to limit the intake capacity and velocity requirements commensurate with that achievable with a closed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulations for existing facilities were promulgated in August 2014. These rules were also challenged and undergoing judicial review. 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. The rules do not specify national BTA standards for minimizing entrainment mortality, but instead require that **EGLE** ~~the MDEQ~~ establish the BTA entrainment requirements for a facility on a site specific basis. These BTA requirements are established after consideration of the specific factors spelled out in the rule. Facilities with actual flows in excess of 125 million gallons per day must provide an entrainment study with its National Pollutant Discharge Elimination System (NPDES) permit application. 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** ~~the MDEQ~~ 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 limitations 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. Multiple petitions for review challenging the regulations were consolidated in the United States Court of Appeals for the Fifth Circuit on December 8, 2015. On April 25, 2017, the **US**EPA issued an administrative stay of the compliance dates in the ~~effluent limitations guidelines~~ **ELGs** and standards rule that ha**d** not yet passed pending judicial review. In addition, the **US**EPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the

USEPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the **US**EPA provided notice that it ~~will~~ **would** conduct a rulemaking to ~~potentially~~ revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash **(BA)** transport water and flue gas desulfurization wastewater **(FGD)**. **The EPA published the regulations on ~~Octobr~~October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the EPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the EPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. EPA intends to publish the proposed rulemaking for public comment in the fall of 2022.** ~~The EPA will provide notice and an opportunity for comment on any proposed revisions to the rule and will notify the United States Court of Appeals that it seeks to have challenges to those portions of the rule severed and held in abeyance pending completion of the rulemaking.~~ On September 18, 2017 the 120day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG **was** ~~is~~ November 1, 2020. ~~, while the latest compliance date of December 31, 2023 remains unchanged.~~

State Rules and Laws:

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 electric generating units must choose one of three methods to comply with the emission limits and any new electric generating unit 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 (MEPA) – Part 17 of Michigan's Natural Resources and Environmental Protection Act (NREPA), 1994 PA 451.

Under MEPA, the attorney general 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 coal ~~combustion residuals (~~CCR~~)~~ as a solid waste. It requires any CCR that will 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 the financial assurance to conduct groundwater monitoring throughout the post-closure care period.

The disposal facility is required to maintain the 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 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 regulation of CCR units. **Under the amendment, u**~~U~~pon 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 the majority of the RCRA regulations w~~h~~ould 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 the majority of the RCRA rule, including the regulation of CCR surface impoundments used for storage. Michigan's request for state program approval is currently under review by the USEPA.** ~~Michigan is in the process of developing a permit program for submittal to the EPA.~~

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

A list of federal and state environmental regulations, laws and rules formally proposed have been identified as required by Section 6t (1) (d):

Ozone Nonattainment Areas – Following the 2020 ozone season, design values for ozone monitors located in all four of the nonattainment

areas did not demonstrate attainment with the 2015 ozone NAAQS; therefore, it is anticipated that the nonattainment areas will be reclassified by EPA in February 2022 from marginal to moderate nonattainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional elements to reduce emissions to attain the standard. Required moderate nonattainment planning elements include reasonably available control technology, reasonable further progress, a motor vehicle inspection and maintenance program (southeast Michigan only due to the population threshold), and an attainment demonstration.

~~The ozone NAAQS was revised by the **US**EPA in 2015 from 75 ppb to 70 ppb. Nonattainment designations were to be made by October 2017. In June 2017, the **US**EPA announced a decision to delay making designations by one year. More recently on August 2, 2017, the **US**EPA withdrew its plan to delay designations. Michigan is expecting ten counties, or portions of counties, to be designated nonattainment, including Wayne, Oakland, Macomb, St. Clair, Livingston, Washtenaw, and Monroe in Southeast Michigan and Muskegon, Allegan, and Berrien in West Michigan. Deadlines and requirements for ozone nonattainment areas are dependent on the classification assigned to the nonattainment area. All ozone nonattainment areas in Michigan are expected to be classified "Marginal". This classification would establish an attainment deadline of 2020 or 2021 depending on the date of designation, and an attainment plan submittal deadline of 2020 or 2021. In addition to the requirement to attain by the deadline, there will also be more stringent requirements for major source air permits, including lowest achievable emission rate conditions and offsets for new emissions of the ozone precursors of nitrogen oxides and volatile organic compounds.~~

In September 2021, it became apparent that current ozone data in southeast Michigan was displaying values that could potentially allow for attainment with the 2015 standard. Meetings were schedul~~lu~~ed with the USEPA and a redesignation request was drafted. Following the closure of the ozone season on October 31, 2021, design values were calculated and it was determined that southeast Michigan had attained the standard using years 2019, 2020, 2021 ozone season data. The redesignation request was put out for public comment in November ~~2120~~2021, and it is anticipated that the request will be submitted to USEPA in ~~December~~ January 2022~~1~~. Should USEPA approve the redesignation requ~~i~~est, southeast Michigan will become maintenance for the 2015 ozone standard.

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

Commented [A1]: Company Response - We believe this request was not submitted in December.

"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** ~~utilities~~ generation fleet, and include the relevant future compliance costs within the IRP model. Review and approval of an electric utility's integrated resource plan by the Michigan Public Service Commission does not constitute a finding of actual compliance with applicable state and federal environmental laws. Electric utilities that construct and operate a facility included in an approved integrated resource plan remain responsible for complying with all applicable state and federal environmental laws.

V. 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 local clearing requirements 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 (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.[13] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins ~~2018~~ **2022** through ~~2027~~

[13] MISO **2022-2023** ~~2018 – 2019~~ Loss of Load Expectation Study Report published on **November 1, 2021** ~~October 2017~~, ~~https://www.misoenergy.org/Library/Repository/Study/LOLE/2018%20LOLE%20Study%20Report.pdf~~ **https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.**

2031" for the entire footprint.[14] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[15] The local reliability requirement is a measure of the planning resources required to be physically located inside a local resource zone 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 Local Clearing Requirement is defined as "the minimum amount of unforced capacity that is physically located within the Zone that is required to meet the LOLE requirement while fully using the Capacity Import Limit for such."[16] The Local Clearing Requirement for each zone is reported annually with the MISO planning resource auction results in April.[17]

Commented [A2]: Company Response – revisions may be necessary to this section later in the updating process, as more information becomes available on the MISO seasonal construct

For the southwest corner of the Lower Peninsula, in PJM's territory, [18] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[19] 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 local resource zones. PJM publishes a Reserve Requirement Study[18] 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 integrated resource plans under Section 6t are also required to annually make demonstrations to the MPSC that they have

[14] Three of the next ten years planning reserve margins are modeled by MISO and the remaining of the ten years are interpolated and reported in the MISO Loss of Load Expectation Study.

[15] MISO models the local reliability requirement for the prompt year, one of the future years in between year 2 and year 5, and one future year in between year 6 and year 10.

[16] Federal Energy Regulatory Commission Electric Tariff, Module E-1, 1.365a. 1.0.0.

[17] MISO Planning Resource Auction results, April **2021** ~~2017,~~ ~~https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017- 2018%20Planning%20Resource%20Adequacy%20Results.pdf~~. **https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf**

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

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

[18] PJM Reserve Requirement Study, October ~~2017~~ **2021**, ~~http://www.pjm.com/-/media/committees-groups/committees/mrc/20171026/20171026-item-05-2017-irm-study.ashx~~. **https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjmreserve-requirement-study.ashx**

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 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 State Reliability Mechanism under Section 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VI. Modeling Scenarios, Sensitivities and Assumptions

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

For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, ~~three~~ **two** modeling scenarios are required. ~~There is a total of four unique scenarios included in this IRP parameters document; the applicability of each is described within the narrative of each particular scenario~~. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in PA 341 Section 6t (4) regarding multistate IRPs, Northern States Power-Wisconsin and Indiana Michigan Power Company are intentionally excluded from the explicit requirement to model the outlined scenarios. However, the multistate utilities are encouraged to include the provisions included in each scenario. The Commission may request additional information from multistate utilities prior to approving an IRP pursuant to Section 6t (4) of PA 341.

Scenario 1: Base Case

~~(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7) The existing generation fleet (utility and non-utility owned) is largely unchanged apart from new units planned with firm certainty or under construction. No carbon regulations are modeled, although some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and~~

~~goals, as well as economics.~~

This scenario reflects ~~substantial achievement of state and utility announcements. While Scenario One incorporates 100% of utility integrated resource plan (IRP) announcements throughout the MISO footprint, state and utility goals and announcements~~unit retirements defined in MISO's most recently available Future 1 and utilizing best efforts to incorporate more-recent public announcements made by MISO electric utilities and independent power producers ~~that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these goals and announcements at their proposed respective timelines.~~ Carbon ~~e~~Emissions decline as driven by state goals and utility plans throughout the MISO footprint creating a trajectory of at least 40%~~63%~~ reduction in carbon emissions by 2039 from the baseline year of 2005. This scenario assumes that demand and energy growth are driven by existing economic factors with~~, with small~~ moderate increases in EV adoption~~, resulting in an annual energy growth rate of 0.5%.(cite 2021 MISO Futures Report)~~

- ~~Natural gas prices utilized are consistent with **the Reference Case** business as usual projections as projected in **from** the United States Energy Information Administration's (EIA)~~ **Natural gas prices utilized are consistent with the Reference Case business as usual projections as issued from the most recent United State Energy Information Administration's Annual Energy Outlook. The filing utility may utilize a different forecast if it is publicly available or can be made available through confidentiality agreements. The filing utility will have the burden to justify the use of a forecast that is not the most recent EIA-AEO reference case**. ~~most recent Annual Energy Outlook reference case.~~[19]
- **Moderate EV adoption and customer electrification result in modest utility demand and energy growth rates. Electrification growth rates by year 5 of the planning horizon should be assumed at levels specified in MISO Future 1, or higher.**

Commented [A3]: Company Response – Staff mentioned in the stakeholder engagement session that the 63% came from MISO's modeling results using a 40% carbon reduction trajectory. The Company recommends that the number used in the Base scenario better align with MISO Futures and utilize either the 40% carbon reduction specified in MISO Future 1, or if a more aggressive target is desired set this reduction at 60%. This sets carbon reduction targets at more standard levels as opposed to the reduction number being based on a single MISO modeling run performed in one year.

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

- ~~**Moderate EV adoption and customer electrification result in moderate f**~~footprintwide[20] demand and energy growth rates ~~**remain at historic 3-year average levels for the first 3 years of the planning horizon, then are blended for 2 years to result at the load growth level consistent with the most recently available MISO Future 1 after the fifth year of the planning horizon;**~~ . ~~remain at low levels with no notable drivers of higher growth; however, as a result of low natural gas prices, industrial production and industrial demand increases.~~
- ~~Low natural gas prices and low economic growth reduce the economic viability of other generation technologies~~.
- Resource assumptions:
  - ~~Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).~~
  - **Resources outside MI – retirements are defined in MISO Future 1 assumptions and with best efforts to incorporate more recent public announcements.**
  - Resources within MI – Thermal and nuclear generation retirements in the modeling footprint are ~~driven by a maximum age assumption~~**defined in MISO Future 1 assumptions**, public announcements, or economics.
- Specific new units are modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), **IRP cost pre-approval**, or signed generator interconnection agreement (GIA)).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).

- **The plan meets current state and federal goals for greenhouse gas emissions.[23,24]**
- For all instate electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under

~~[20] Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.~~

the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include an EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap.[21]

- ~~For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.~~
- ~~Existing renewable energy **and storage** production tax credits and renewable energy investment tax credits~~ **Production, investment, and other tax credits applicable to the electric utility industry** continue pursuant to current law.
- **Long and short duration storage resources are considered. ~~Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.~~**
- 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 demand response programs will be determined by **the state-wide** ~~their respective~~ potential studi~~es~~**y**. **Each filing utility may further break-out the state-wide study to reflect its specific customers and service territory.**
- **Technology costs for solar, storage, and other emerging technologies** ~~Technology costs for solar, **storage,** and other emerging technologies decline with commercial experience~~**track with mid-range industry expectations**.
- ~~Existing PURPA contracts are assumed to be renewed~~.
-
- ***Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF publicly indicates, or indicates directly to the utility, otherwise.***
- ***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 publicly indicates, or indicates directly to the utility, otherwise.***

Commented [A4]: Company Response – please note that the potential study referenced ends in 2040, but these requirements will apply to IRPs that have a planning horizon beyond 2040. The utilities will need to modify and extend forecasts beyond the projections of the state-wide study.

Commented [A5]: Company response – edits for consistency with PURPA edits above.

[21] For EWR cost supply curves, see the **Michigan Energy Waste Reduction Potential Study (2021-2040) Report** ~~appendices in the supplemental potential study for the Lower Peninsula~~ at this link: ~~http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf~~. **https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Final_Draft_Report_732747_7.pdf** [26] **For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.**

Scenario #1 Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to **a forecast consistent with** ~~at least~~ **the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast** ~~200% of the business as usual~~ natural gas fuel price projections at the end of the study period.[26] **The filing utility may utilize a different forecast if it is publicly available or can be made available through confidentiality agreements. The filing utility will explain the basis for the use of a forecast that is not the most recent EIA Low Oil and Gas Supply forecast.**

2. Load projections
   (a) ~~High load growth: Increase the energy and demand growth rates by at least a factor~~

[23] 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.

[24] 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.

~~of two above the base case energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base case load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.~~ **(a) High load growth: Electrification drives a total energy growth through the 20-year planning horizon that is consistent with the most recent MISO Future 3. Utility load profiles and peak demand are adjusted to reflect the increased EV and electrification.**

   (b) **Low load growth: EV adoption and electrification are slower than expected and the demand and load growth stay at historic levels. Utility load profiles and peak demand are**

adjusted to reflect the utilities load growth with slower EV adoption and electrification.

(c) If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by **2027~~3~~**.

3. Ramp up the utility's EWR savings to at least 2.0~~5~~%[27] of prior year sales over the course of four years, using EWR cost supply curves provided in the Appendix G of the 2017 supplemental potential study for more aggressive potential.[28] EWR savings remain high throughout the study period.

~~4. Sensitivity allowing only natural gas fired simple cycle combustion turbines to be selected by the model. **Perform a model run that optimizes the resource build**~~

~~4.~~5. **A sensitivity that considers only legislatively mandated carbon goals and does not consider non-legislatively mandated carbon goals.**

6. ~~**Out-of-State transmission congestion cost increases due to changing resource mix across the region. Assume transmission cost increases of XX%**~~ **Out-of-state transmission congestion results in increased cost of energy imported into Michigan. Assume transmission cost increases of XX%.**

Commented [A6]: Company Response – the utility may find that load growth projections are not expected to remain at historic levels but to grow even when EV adoption and electrification are slow to grow. It would be prudent to have the opportunity to adjust profiles if it is necessary.

Commented [A7]: Clarification Request - This sensitivity needs additional discussion and clarification; it is unsure at this time what the goals and structure of this sensitivity are. The Company has made an attempt to re-word this sensitivity based on the impacts of transmission congestion

[27] **2021 Energy Waste Reduction Potential Study, Appendix D.** [28] **Cite appropriate part of the EWR potential study.**

Scenario 2. ~~Electrification and~~ Decarbonization Future

Commented [A8]: Company Response - Electrification is one potential pathway to decarbonization, but it isn't the only pathway. Recommend simplifying to "Decarbonization Future," without highlighting one potential pathway.

This scenario reflects unit retirements defined in MISO Future 3 and utilizing best efforts to incorporate more-recent public announcements made by MISO electric utilities and independent power producers. ~~This scenario incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario requires a minimum penetration of wind and solar across the MISO region consistent with the most recent~~ This scenario assumes utility electric needs are met through a combination of demand-side management and renewable energy at levels not less than the percentage of renewable energy achieved in MISO Future 3.[22] Carbon emissions decline as driven by state goals and utility plans throughout the MISO footprint, creating a trajectory of at least 80% reduction by 2039. Energy purchases are modeled at a carbon intensity (US-Tons/MWh) defined and justified by the utility, based upon the MISO fuel mix ~~consistent with the MISO system average.~~ Electrification drives a total energy growth ~~by 2040~~over the 20-year planning horizon that is consistent with the most recent MISO Future 3. Utility load profiles and peak demand are adjusted to reflect the increased EV and electrification.

~~Emerging Technologies~~

~~(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)~~

~~Technological advancement and economies of scale result in a 35% reduction in costs for demand response, EWR programs, and other emerging technologies.[23] For example, costs identified in the demand response potential study should be reduced by 35% for demand response resources. No carbon reductions are modeled, but some reductions occur due to coal unit retirements, and higher levels of renewables, demand response, and energy~~

[22] **The most recent, final, and publishedMISO future s are published on the MISO website: https://www.misoenergy.org/planning/transmissionplanning/futures-development/**

[23] ~~Emerging technologies includes, but is not limited to large-scale and small-scale battery storage, large-scale and small-scale solar, and combined heat and power. See Section IX, Michigan IRP Modeling Input Assumptions and Sources in this document for a full list of potential emerging technologies also could be considered to include as resources with reduced costs in this scenario.~~

~~waste reduction. Load forecasts and fuel price forecasts remain at levels similar to the Business as Usual Scenario.~~

- ~~Technological advancement and economies of scale result in a greater potential for demand response, energy efficiency, and distributed generation as well as lower capital cost for renewables.~~
- ~~Thermal generation retirements in the market are driven by unit age-limits and announced retirements (consistent with business as usual). Company-owned resource retirements may be defined by the utility, however, a meaningful analysis of whether coal units should retire ahead of business as usual dates should be performed. Retirements of all coal units except the most efficient in the utility's fleet should be considered, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics. Retirement of older fuel oil-fired generation should also be considered in this scenario. Units that are not owned by the utility shall not retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset.~~
- ~~Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).~~
- ~~Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.~~
- ~~Prior to and during the modeling process, the utilities shall take into account resources that include, but are not limited to: small qualifying facilities (20 MW and under),~~

~~renewable energy independent power producers, large combined heat and power plants, and self-generation facilities such as behind-the-meter-generation (btmg) as more fully described in section IX, Michigan IRP Modeling Input Assumptions and Sources.~~

- ~~Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.~~
- ~~Technology costs for thermal units remain stable and escalate at moderate escalation rates.~~
- ~~Technology costs for EWR and demand response programs will be reduced 35% from the level determined by their respective potential studies.~~

~~Technology costs for energy storage resources decline over time, particularly battery technologies and others which~~

~~can enable supply- and demand-side resources.~~

- ~~Existing PURPA contracts are assumed to be renewed.~~

~~Emerging Technologies Sensitivities:~~

1. ~~Fuel cost projections~~
   - ~~(a) Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period.~~ [31]

2. ~~Load projections~~
   - ~~(a) High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.~~

3. ~~Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in Appendix G of the 2017 supplemental potential study for more aggressive potential.~~[32] ~~EWR savings remain high throughout the study period.~~

4. ~~Increase the use of renewable energy in the utility's service territory to at least 25% by 2030.~~

~~Scenario 3. Environmental Policy~~

~~(Applicability: Utilities located in MISO Zone 7)~~

[31] ~~For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.~~

[32] ~~For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.~~

~~Carbon regulations targeting a 30% reduction (by mass for existing and new sources) from 2005 to 2030 across all aggregated unit outputs are enacted, modeled as a hard cap on the amount of carbon emissions, driving some coal~~

~~retirements and an increase in natural gas reliance. Increased renewable additions are driven by renewable portfolio standards and goals, economics, and business practices to meet carbon regulations.~~

- ~~Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast and are consistent with the business as usual projections.~~
- **Natural gas prices utilized are consistent with the Reference Case business as usual projections as issued from the most recent United State Energy Information Administration's Annual Energy. The filing utility may utilize a different forecast if it is publicly available or can be made available through confidentiality agreements. The filing utility will explain the basis for the use of a forecast that is not the most recent EIA-AEO reference case**~~Natural gas prices utilized are consistent with reference case projections as projected in the EIA's most recent Annual Energy Outlook reference case.~~[24]
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they are economically selected by the model to help comply with the specified carbon reductions in this scenario.
- **EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.**
- ~~Non-nuclear, non-coal generators will be retired in the year the age limit is reached and driven by announced retirements. Coal units will primarily be retired based upon carbon emissions and secondarily based upon economics. Nuclear units are assumed to have license renewals granted and remain online.~~
- **Retirements are defined in MISO Future 3 assumptions or by more recent public announcements.**
- Specific new units are modeled if under construction or with regulatory approval (i.e.**IRP cost pre-approval**, CON, or signed GIA).
- Generic new resources ~~(market and company-owned)~~ are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.

[24] ~~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 also including delivery costs from Henry Hub to the point of delivery.~~

Commented [A9]: Company Response – in addition to the suggested changes to the natural gas price forecast options utilized in this scenario, under this type of scenario coal prices may actually increase from historical values. This scenario may also need to consider changes or sensitivities associated with coal prices

- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- **The plan meets current state and federal goals for greenhouse gas emissions.**[25,26]
- ~~Tax credits for renewables continue until 2022 to model existing policy~~. ~~**Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law.**~~
- ~~**Existing renewable energy production and storage tax credits and renewable energy investment**~~**, investment, and other tax credits applicable to the electric utility industry continue pursuant to current law.**
-

- Technology costs for ~~wind,~~ solar, storage and other ~~renewables~~ **emerging technologies** decline with commercial experience and forecasted at levels ~~35~~ **30%** lower than in the base case, **by the end of the study period**.
- Non-carbon dioxide emitting resources will be increased, due to the constraint on allowable carbon emissions in the model.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by the~~ir~~ respective **state-wide** potential **study**~~ies~~. **Each filing utility may further break-out the state-wide study to reflect its specific customers and service territory.**
- ~~Existing PURPA contracts are assumed to be renewed.~~

- ***Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF publicly indicates, or indicates directly to the utility, otherwise.***
- ***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***

Commented [A10]: Company Response – 30% reduction from the base forecast by the end of the study period

[25] 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.

[26] 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.

the QF publicly indicates, or indicates directly to the utility, otherwise.

Commented [A11]: Company response – edits for consistency with PURPA edits above.

Scenario #2 Sensitivities:

1. Fuel cost projections
    (a) Increase the natural gas fuel price projections from the base projections to at least ~~200% of~~ the ~~business as usual~~ **high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast** natural gas fuel price projections at the end of the study period. [27]

~~2. Load projections~~

~~High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.~~

~~3.~~ ~~5~~**80**% carbon reduction in the utility's service territory, modeled as a hard cap on the amount of carbon emissions, by 2030 as a sensitivity.[28]

~~4.~~ Ramp up the utility's EWR savings to at least 2.0%[38] of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential.[29] EWR savings remain high throughout the study period.

Commented [A12]: Company Response - highlighted in yellow, because in the Base Case this is highlighted with a note that an update will be performed to reference the more recent study.

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[27] For example, ~~200% of~~ the most recent **EIA AEO Low Oil and Gas Supply natural gas price** ~~EIA AEO reference case natural gas price~~ is **$8.41/MMBtu ($2019)** ~~$10.14/MMBtu ($2016)~~ **in 2040.**

[28] **Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statementsreleases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-goodpaying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/** [38] **2021 Energy Waste Reduction Potential Study, Appendix D.**

[29] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Final_Draft_Report_732747_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

~~5.~~ **~~Out-of-State transmission congestion cost increases due to changing resource mix across the region. Assume transmission costs increase by XX%.~~ Out-of-state transmission congestion results in increased cost of energy imported into Michigan. Assume transmission cost increases of YY%.**

~~6.~~ **Carbon Price Sensitivity?**

Commented [A13]: Clarification Request - This sensitivity needs additional discussion and clarification, it is unsure at this time what the goals and structure of this sensitivity are. The Company has made an attempt to re-word this sensitivity based on the impacts of transmission congestion

Commented [A14]: Company Response – initial comments regarding inclusion of a carbon price sensitivity are that there are options to model carbon price as a sensitivity, or incorporate a carbon price into the base assumptions of this second scenario and allow utilities to then choose whether it is prudent to run additional carbon sensitivities in this scenario.
The Company's recommendation would be to not specify in the filing or modeling requirements which forecast to use but leave the chosen forecast to the discretion of the utility, with justification for the forecast used. This is due to the following reasons:

(a) Carbon prices in regulated markets (e.g., CA, RGGI, Europe, etc.) have been trending slowly up for a few years now, and that trend is likely to continue – which means we'd want to be able to use the latest data at the time of filing,
(b) Carbon prices vary considerably based on market construct, again suggesting flexibility is warranted
(c) Carbon prices trends can also be observed through what prices are proposed in Congress, which also vary considerably from year-to-year.

~~Scenario 4. High Market Price Variant~~

~~(Applicability: Utilities located in the Michigan portion of MISO Zone 2)~~

~~An increase in economic activity drives higher than expected energy market prices. The existing generation fleet is largely unchanged apart from new units planned with firm certainty or under construction. No carbon regulations are modeled, though some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals, as well as economics.~~

- ~~Natural gas prices utilized are higher than business as usual projections and are consistent with projections in the EIA's most recent Annual Energy Outlook low oil and gas resource technology case[30] where natural gas prices near historical highs drive down domestic consumption and exports.~~
- ~~Footprint-wide[31] demand and energy growth rates are moderate to robust with notable drivers of higher growth.~~
- ~~High natural gas prices and moderate to robust economic growth increase the economic viability of alternative technologies.~~
- ~~Thermal generation retirements in the market are driven by unit age-limits, and announced retirements are driven by age and environmental regulations. Company- owned resource retirements are defined by the utility.~~
- ~~Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).~~

[30] ~~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 also including delivery costs from Henry Hub to the point of delivery.~~

[31] ~~Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.~~

- ~~Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.~~
- ~~Tax credits for renewables continue until 2022 to model existing policy.~~
- ~~Technology costs for thermal units remain stable and escalate at low to moderate escalation rates.~~
- ~~Technology costs for renewables remain stable and escalate at low to moderate escalation rates.~~
- ~~Technology costs for energy efficiency and demand response remain stable and escalate at low to moderate escalation rates.~~
- ~~Existing PURPA contracts are assumed to be renewed.~~

~~High Market Price Variant Sensitivities:~~

2. ~~Fuel cost projections~~
   (a) ~~Increase the natural gas fuel price projections from the base scenario projections to at least 150% of the natural gas price forecast at the end of the study period.~~

   (b) ~~Reduce natural gas fuel price projections to half of the natural gas fuel projections used in this scenario.~~

3. ~~Load projections~~
   (a) ~~High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business as usual load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.~~
   (b) ~~If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by 2023.~~

4. ~~Grid defection: Reduced load due to the development of residential small cogeneration units, solar, batteries, and wind could influence more customers going "off-grid" as electric rates continue to be high in the Upper Peninsula.~~

5. ~~Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential. EWR savings remain high throughout the study period.~~[32]

VII. 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.	

[32] ~~For maximum achievable potential levels, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf;~~
~~See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report_memorandum_08.09.17_598056_7.docx.~~

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~~ **most recent MISO futures** • Public announcements on retirements	• MISO or PJM documented fuel type retirements • All retirement assumptions must be documented
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 forecasts only) • 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/Annual Reports • 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 - Energy Waste Reduction Savings *MWhs*	Base Case: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to load forecast. • For non-incentive earning electric utility, mandated annual incremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should be met through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR **Base Case** ~~Business as Usual~~ Sensitivities: • For savings beyond mandate, incorporate EWR as an optimized generation resource. ~~Emerging Technologies Scenario:~~ • ~~Ramp up EWR savings at least 2.5% over the course of four years, using EWR Cost Supply Curves provided in the 2017 Supplemental Potential Study for More Aggressive Potential (e.g., with 100% incremental cost of incentives, no cost cap and emerging technologies assumptions.) • Consider load shape of EWR measures so on-peak capacity reduction associated with EWR can be reflected.~~	• Utility EWR plan and reconciliation filings • 2020 EWR Potential Studies for Consumers Energy and DTE Energy • 2020 Lower Peninsula EWR Basic Potential Estimate • 2020 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2020 Lower Peninsula EWR Cost Supply Curves
10 - Energy Waste Reduction 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 **2020** ~~2016/2017~~ Potential Studies and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• ~~2016~~**2016**EWR Potential Studies for Consumers Energy and DTE Energy • 2020 Lower Peninsula EWR Basic Potential Estimate • 2020 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2020 Lower Peninsula EWR Cost Supply Curves

11 - Demand Response 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/VAR optimization). • Technical, economic, and achievable levels of demand response as applicable to the scenario.	• As defined by ~~2017 Demand Response Potential Study~~ **2021 Demand Response Potential Study**
12 - Demand Response 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 ~~2017 Demand Response Potential Study~~ **2021 Demand Response Potential Study**
13 - Renewable Capacity Factors		• 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, must be justified, and made available to all intervening parties.
15 - Other/Emerging Alternatives	• Changes to operation guides • Options which improve reliability (SVC, HVDC, volt/VAR) • 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 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, combined heat and power, pumped hydro storage, voltage optimization) • Behind-the-Meter (customer BTM) Generation (e.g., solar photovoltaic (PV), biogas (including anaerobic digesters), combined heat and power (combustion turbine, steam, reciprocating engines), customer-owned backup generators, microturbines (with and without cogeneration), fuel cells (with and without cogeneration), small-scale 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.
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must be provided to all intervening parties.

VIII. Additional IRP Requirements and Assumptions

1. Utility-specific assumptions for discount rates, weighted average cost of capital and other economic inputs should be justified and the data shall be made available to all parties.

2. Prices and costs should be expressed in nominal dollars.

3. The capacity import and export limits in the IRP model for the study horizon should be determined in conjunction with the applicable RTOs and transmission owners resulting from the most current and planned transmission system topology. Deviations from the most recently published import and export limits should be explained and justified within the report.

4. Environmental benefits and risk must be considered in the IRP analysis.

5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, as well as storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled over the planning period. Factors such as geographic location with respect to wind or solar resources and data sources that focus specifically on renewable resources should be considered in the determination of initial capital cost and production cost (life cycle/dispatch).

6. Models should account for operating costs and locational, capital and performance variations. For example, setting pricing for different tranches if justified.

7. 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.

8. The IRP model should optimize the incremental EWR and renewable energy to achieve the 35% goal. However, the model should not be arbitrarily restricted to a 35% combined goal of EWR and renewable energy. Exceeding the combined EWR and renewable energy goal of 35% by 2025 shall not be grounds for determining that the proposed levels of peak load reduction, EWR and renewable energy are not reasonable and cost effective.

9. 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.

10. Prior to modeling the **Base Case and the Electrification and Decarbonization scenarios** ~~Business as Usual, Emerging Technologies, Environmental Policy, or High Market Price Variant Scenarios~~, the utilities shall consider and prescreen all of 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.

11. Consider including transmission assumptions in the IRP portfolio, such as the impact of transmission and non-transmission alternatives (local transmission, distribution planning, locational interconnection costs, environmental impacts, right of way availability and cost) to the extent possible.

12. 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.

13. 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.

14. Recognize capacity and performance characteristics of variable resources.

15. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.

16. Take into consideration existing power purchase agreements, green pricing and/or other programs.

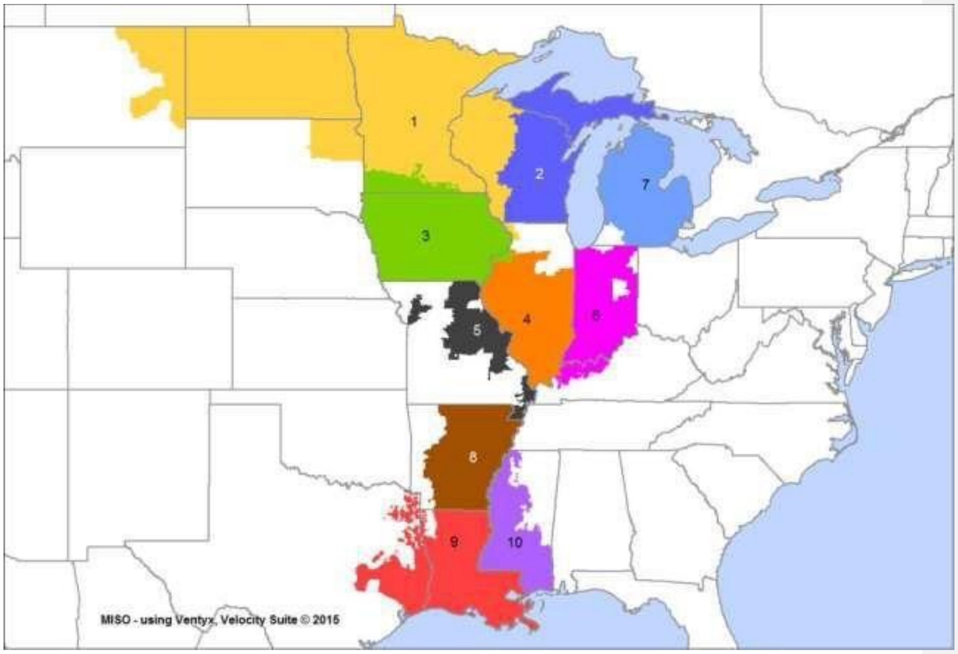
17. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the net present value of revenue requirements.

18. An analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.

Appendix A: Organization Participation List: The workgroups consisted of people from the following organizations or groups:

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones

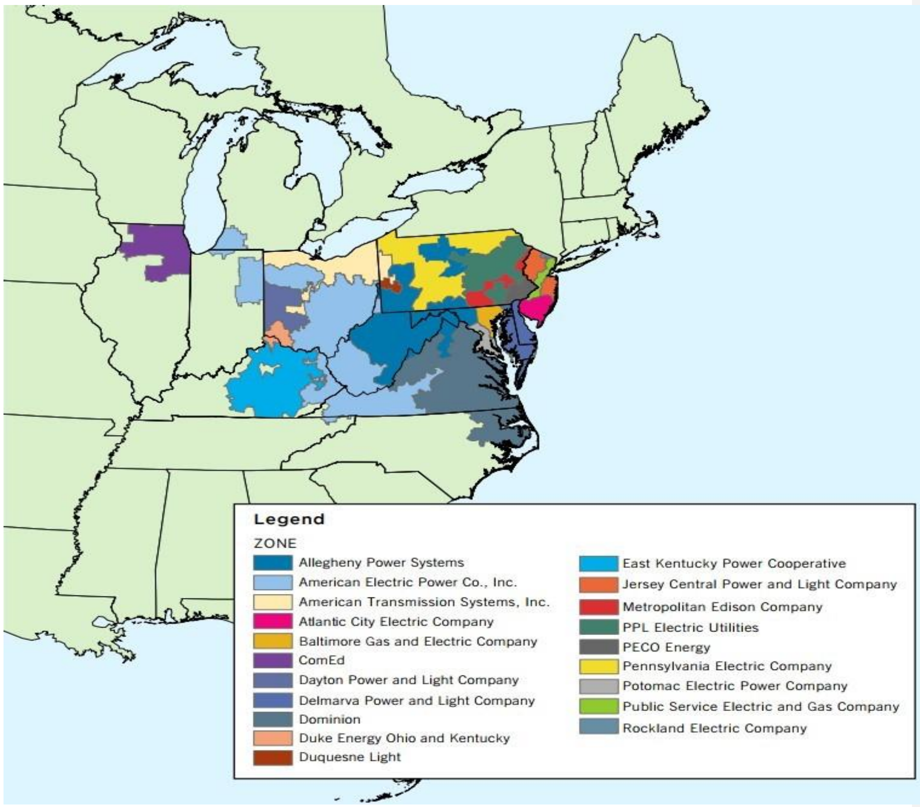


MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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, within 120 days of the effective date of the amendatory act that added this section and every 5 years thereafter, commence a proceeding and, in consultation with the Michigan agency for energy, the department of environmental quality, 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, based on what is economically and technologically feasible, as well as what is reasonably achievable.

(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 shall 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, and projected load management and demand response savings.

  (iv) Any regional infrastructure limitations in this state.

  (v) The projected costs of different types of 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.

Appendix E: Environmental Regulatory Timeline - Update from Previous

Updated 8-18-2017

DTE

DTE Electric Comments Regarding Staff's Draft Report circulated 12-15-2021 MI Power Grid– Advanced Planning Phase III

January 7, 2022

On December 15, 2021, Michigan Public Service Commission's (MPSC or Commission) Staff prepared initial redlined Integrated Resource Planning (IRP) filing requirements and Michigan IRP Parameters (MIRPP).

DTE appreciates the effort of the Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this integrated planning collaborative. DTE will provide comments on the sections as laid out in Staff's report as well as the recommendations provided.

DTE looks forward to further discussions and collaboration with Staff and industry stakeholders on Michigan's integrated planning process.

Staff asked for feedback on the following:

1. Please provide any feedback supporting or suggesting changes to Staff's proposed MIRPP
2. Please provide any feedback supporting or suggesting changes to Staff's proposed Filing Requirements
3. Are stakeholders generally supportive of two MIRPP scenarios for all rate regulated utilities?
4. Do Stakeholders feel that the Electrification and Decarbonization scenario would adequately take the place of the two additional runs directed by the Commission in the February order in U-20633?
5. Considering ED 2020-10 and other carbon goals, how do we more accurately count GHGs without double counting purchases and sales between utilities within the Michigan?

#1 - MIRPP

Please see attached document 01 Phase III MIRPP Draft - Redline for Dec 16 - DTE Comments for comments and suggestions. As noted in the document, DTE would like additional discussion and clarification on the use of MISO Futures in the scenarios.

#2 - Filing Requirements

Please see attached document for 02 IRP Filing Requirements Draft - December 16 Stakeholder Meeting - DTE Comments for comments and suggestions

DTE supports a smaller subgroup to discuss the Environmental Considerations and Environmental Justice section of the filing requirements.

#3 - Are stakeholders generally supportive of two MIRPP scenarios for all rate regulated utilities?

In general, DTE is supportive of streamlining and updating the scenarios to reflect a more current state of the energy industry and the most current policy. In addition, DTE is supportive of going to two bookend scenarios instead of three. This leaves flexibility for the utilities to run additional scenarios if they desire to. This approach is also aligned with the recommendations of the Michigan Council on Climate Solutions. As mentioned is the response to Q1, more discussion is needed on what the MIRPP scenarios are and how these are modelled.

#4 - Do Stakeholders feel that the Electrification and Decarbonization scenario would adequately take the place of the two additional runs directed by the Commission in the February order in U-20633?

DTE feels that an electrification and a decarbonization scenario could address the Order in U-20633 although has concerns about the recommended use of MISO futures as the base for the scenarios and feels additional discussion and clarification are needed.

#5 - Considering ED 2020-10 and other carbon goals, how do we more accurately count GHGs without double counting purchases and sales between utilities within the Michigan?

DTE is a proponent of the annual net short approach to carbon accounting. Before our last IRP, we evaluated five methods of carbon accounting, described here:
https://www.epri.com/#/pages/product/000000003002015044/?lang=en-US
We selected the annual net short method in our last IRP because we determined that it did the best job to capture the true impact of Carbon emissions of the power used by our customers - using the tools that we had in place. The Annual Net Short method relies on quantifying a marginal ton of CO_2 to be based on a gas unit and attributing that to purchases and sales.

In the annual net short method, the Company's generating units are divided into two groups: non-dispatchable and dispatchable. For the purposes of the annual net short carbon accounting method dispatchable refers to gas units, frequently on the margin serving the broader market ups and downs while non-dispatchable refers to the traditional baseload resources, renewables, and purchase contracts with specific assets. The non-dispatchable units' emissions are assumed to stay with the Company, as these resources are assumed to be always serving our customers. Therefore, DTE Electric's coal, nuclear, and renewable assets, and all PPAs are considered non-dispatchable for the purposes of carbon accounting. Dispatchable units are more likely to be on the margin and able to quickly ramp up and down to supply power to the MISO market and includes all gas units (CCGT and gas peakers). The generation and the associated emissions from the non-dispatchable units are summed separately. Then the generation from the Company's non-dispatchable units are subtracted from the DTE Electric customers' load. The difference is what is required to serve our customers' load, beyond the output of the non-dispatchable units. This difference could be positive ("net short") when the Company needs to purchase additional electricity to serve its customers on an annual basis, or this difference could be negative if the Company is a net seller of electricity over the course of the year. A CO_2 intensity (pounds/MWh) corresponding to the U.S. natural gas fleet is applied to this difference. A gas fleet intensity was used as the basis for this carbon intensity calculation because gas units (CCGT and CT) are frequently marginal units supplying the market, meaning they are the next units to dispatch and thus set the market price. Renewables, base-load coal, and nuclear are not typically considered marginal units in the market.

We look forward to continuing conversations on the MIRPP and filing requirements

EXHIBIT A

DRAFT

Integrated Resource Plan Filing Requirements for December 16th Stakeholder Meeting

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

These application instructions apply to a standard electric utility application for Michigan Public Service Commission (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, 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 a 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. If a

[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.

certificate of necessity (CON) is also being filed, the same filing announcement would serve as the filing announcement 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; and
d) Information related to any CON application that would be filed with the utility's IRP.

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 with 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 proposals (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 with the IRP application documentation demonstrating that the RFP process was completed;
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, and Commission rules;

d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, 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 purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Stakeholder 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; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

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 the 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. Documentation may 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; and

f) Discussion indicating if or how the public outreach process influenced the IRP.

A minimum of two stakeholder engagement workshops are recommended. A stakeholder engagement workshop will provide stakeholders with 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 invite stakeholders, including expected intervenors and the Staff, to its stakeholder engagement workshops.

If the stakeholder engagement workshops are not open to the public, two additional public meetings are recommended. 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 public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advanced notice provided to customers in the utility's service territory. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

If the utility chooses to hold pre-filing workshops, including stakeholder 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 should be maintained on a website in a location open to the public for the duration of the stakeholder 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 analysis of the ~~preferred plan~~ **proposed resource plan** and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as a diverse mix of relevant builds selected from the other scenarios and sensitivities ~~all additional scenarios and sensitivities~~ filed with the IRP application. The plans should be feasible and differ in generation mix from the **proposed resource plan** ~~preferred plan~~ and MIRPP plans. The intent of the risk assessment is to test the optimized resource

Commented [ANL1]: DTE Comment: DTE suggested wording change to align with part D and streamline work strategies for each scenario to determinehow each strategy would perform in an unexpected range of possible futures. The IRP shall include a discussion of the methodology used for risk analysis including the utility'sjustification for the chosen methodology over other alternatives. Acceptable forms of risk analysis 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.

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.

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 facilities, 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:

I) For specific supply-side resources (inclusive of storage technologies such as battery storage) of less than 225 megawatt (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators,storage facilities, etc.), that have not yet been approved by the Commission and are planned to go into service within three years following the approval of the IRP, the following evidence (covering the

Commented [ANL2]: DTE added suggested wording "have not yet been approved by the Commission and"

Commented [ANL3]: DTE comment: suggest removing "and" that is in the pdf version released on the 16th of December 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:
    i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
    ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
    iii. 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.
d) Projected property taxes;
e) The rates of escalation of cost, including:
    i. Capital costs;
    ii. O&M costs which are variable and related to fuel;
    iii. O&M costs which are variable and unrelated to fuel; and
    iv. 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 power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.**

o) **A description of the decommissioning process and ~~,~~ costs for applicable new resources, , and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling.**

Commented [ANL4]: DTE comment: could you provide clarification on this addition and what the intent of this addition was? Is it only when you are adding new resources in the first three years due to retirement? Is this specific to power plants or all generation assets?

Commented [ANL5]: DTE Comment: added suggested wording to clarify that this is only required if there are any applicable related decommissioning costs

II) Renewable Resources: The utility shall file data consistent with its renewable energy plan. (For incremental renewable energy beyond the 15% requirement in 2021 and any renewable energy to be constructed or purchased after the conclusion of the 20-year renewable planning period ending in 2029, the utility shall file as set forth below.) Revenue requirement and incremental costs of compliance shall be calculated to include the following:

a) Capital, operating and maintenance 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) Ancillary service costs.

e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance.

f) Cost of Contracts.

g) Expenses incurred as a result of governmental action including changes in tax or other laws.

h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.

i) 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); and

j) Provide the following information in relation to renewable resource cost recovery:
   i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
   ii. Forecast through the end of the renewable plan period of the regulatory liability balance.

k) **Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.**

l) **A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling.**

Commented [ANL6]: DTE Comment: see above comment

III) Energy Waste Reduction: The utility shall providethe following information in relation to ~~demand response programs,~~ energywaste reduction programs~~, and distributed generation programs~~ cost approval and recovery. For each individual program or group of programs,provide:

a) Total annual cost including:
   i. Annual O&M cost for each individual portfolio of energy waste reduction~~, demand response~~~~, and distributed generation programs;~~
   ii. Annual capital cost for each individual portfolio of energy waste reduction~~, demand response, and distributed generation programs~~; and
   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission;

Commented [ANL7]: Suggest removing "distributed generation programs" to align with section references

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;

c) Maximum single event demand reduction;

~~d)~~ Total resource capacity (MW) and type ~~(load modifying resource, emergency demand response, etc.)~~ reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);

e) Total energy reduction achieved (megawatt-hours (MWh)); and

f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) **Demand Response and Distributed Generation Programs:** **The utility shall provide the following information in relation to demand response programs~~, energy waste reduction programs,~~ and distributed generation programs cost approval and recovery. For each individual program or group of programs, provide:**

a) **Total annual cost including:**

   i. **Annual O&M cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs; Minor miscellaneous expenses that are shared across programs will be split evenly amongst programs.**

   ii. **Annual capital cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs; and**

   iii. **Expected cost-sharing or financial incentive granted to the utility by the Commission;**

b) **Total demand reduction potential (MW), including the maximum amount of projected peak load reduction and program parameters to include number of interruptions allowed, months, days, hours and length of interruptions ~~and the expected hours of interruption per day, month, and year~~ for each program, if applicable;**

c) **Maximum single event demand reduction;**

d) **Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);**

e) **Total energy reduction achieved (megawatt-hours (MWh)); and**

f) **Description of program, including customer enrollment, technology used, and marketing plan.**

Commented [ANL8]: DTE Request: Please clarify what is meant by Distributed Generation. Is this different than distributed energy resources? DG programs is (could be) different than DER. Also, please include a reference as to what the definition is to ensure consistent understanding

Commented [ANL9]: DTE Comment: Include wording addition as some minor O&M expenses are shared between programs and can be spread evenly.

Commented [ANL10]: DTE Comment: Wording modification for clarification

Commented [ANL11]: DTE Comment: can you provide clarification if this is what is expected to be achieved and how does this differ between b?

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 ten 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 ~~Report 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~~ proposed **resource plan** ~~preferred resource plan~~ and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisitionstrategy, acknowledging that the utility

Commented [JEL12]: DTE comment – replace approved with proposed 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** ~~preferred resource plan~~ and resource acquisition strategy;

c) The data and information requested in the Commission's IRP filing requirements included herein; and

d) Any other information deemed relevant by the utility.

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

I) Executive Summary:
An IRP shall include 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** ~~preferred resource plan~~ and resource acquisition strategy.The executive summary shall summarize the contents of the IRP documentand shall include the following:

a) An overview of the planning period examined in the IRP analysis and application; and

b) A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the goal to be achieved by its proposed course of action and implementation strategy.

II) Table of Contents: Shall be provided **for the contents of the filed case.**

III) Table of Figures: Shall be provided **for the contents of the filed case**.

IV) 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

Commented [ANL13]: DTE comment – if there is a requirement for this information in an excel table for each filing requirements as added below DTE does not think this needed? Suggest deleting ll and lll. If this and ll are required – DTE requests an example IRP to benchmark

Commented [ANL14]: DTE comment – see ll 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:
    i. Net present value of utility revenue requirements,[2][1] with and without any financial performance incentives for demand-side resources;
    ii. Revenue requirement of existing generation and power purchase agreements;
    iii. Summary of existing generation and power purchase agreements by fuel type;
    iv. Utility's existing capacity resource mix;
    v. Utility's service territory and breakdown of customer class composition; and
    vi. Description of planning period analyzed;
b) Statement of power need;
c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis 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:
    i. RTO market and state regulation structure if a multistate utility;
    ii. Potential changes to RTO capacity market;
    iii. Electric customer choice;
    iv. Transmission expansion;
    v. Environmental;
    vi. Renewable portfolio standards; and
    vii. Other;
e) IRP planning process; and
f) Stakeholder report.

[1] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Resultsshould be presented in nominal dollars

V) Analytical Approach:

a) Describe the modeling process, including the duration of the study;

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

i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various ~~preferred~~ resource plan options;

ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan;

iii. **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.**

c) 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 ~~preferred~~ 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.

d) **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 for the proposed resource plan and any alternative resource plans presented by the utility.**

VI) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities;

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-**XXXXX**, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VII) Existing Supply-Side (Generation) 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) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource;
h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.);
i) Spot market purchases and off-system sales.

VIII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
   i. Description of current demand response 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;

ii. **Historic performance of existing demand-side programs and how the utility used such information in its demand response resource decisions;**

Commented [ANL15]: DTE Request: Could you define and clarify what "historic performance" means as it relates to this section? Can you provide examples? Would test runs to evaluate pilots and programs need to be included? What is the timeframe?

iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response;;

iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

IX) Renewables and Renewable Portfolio Standards Goals:

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 renewable energy credit 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 goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
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.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast ~~through 2021 for compliance with the renewable energy standard,~~ through 2025 toward meeting the 35% goal, and through the study period;

b) Detailed resource plan:

   i. Describe the utility's planned renewable energy credit portfolio;

   ii. Forecast RECs obtained via Michigan incentive RECs;

   iii. Forecast expected compliance levels by year to meet the renewable portfolio targets;

   iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio;

   v. Identify risks which may drive performance to vary.

X) 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 energy waste reduction 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, and the actions the utility proposes to take in order to achieve that peak demand reduction;

b) Subsections:

   i. Key variables used to develop forecast;

   ii. Long-term forecasting methodology;

   iii. Forecasting uncertainty and risks;

   iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers);

   v. **Base Case**~~Business as usual~~ deliveries and demand forecast;

   vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. **U-XXXXX**, or subsequent Commission orders relating to IRP modeling parameters and requirements.

   vii. ~~Include detailed~~Describe in detail ~~information~~ about

Commented [ANL16]: DTE Comment: Consider deleting, as this time period is past

Commented [ANL17]: DTE Comment: DTE suggested word change

how the forecasts used for IRP modeling align with forecasts used for distribution planning.

viii. **Detail information about distributed energy resource adoption and operation, including distribution connected generation and storage.**

ix. **Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.**

x. **Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.**

XI) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. 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.

XII) Transmission Analysis:

In accordance with MCL 460.6t(5)(h), the utility shall 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 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;
b) **Include an analysis of any transmission system benefits associated with transmission interconnected storage**
c) A detailed description of the utility's efforts to engage local transmission owners ~~in~~ **throughout** the utility's IRP process. **In an effort to inform the IRP process and assumptions, a meeting**

Commented [ANL18]: DTE Request: Can you define operation in this section? Does this refer to load shape? Please define "distribution connected generation and storage"?

Commented [JEL19]: DTE Comment: The TO or an outside party is best suited to address benefits to the transmission system; in addition, the IRP is not site specific for resource additions therefore site specific transmission benefits would not be quantifiable

schedule should be set in advance. The filing should **include the pre-decided meeting schedule, any documentation that supports requested extensions of the initial pre-decided timing**, **and** ~~including~~ a summary of meetings that **ultimately took** place;

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) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;

Any information provided by the transmission owner(s), including costand timing, indicating potential transmission options that could impactthe utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboringRTOs; (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 ordemand-side resources; **(5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits**.

g) **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 that indicate ways in which the capacity import or export capabilities can be increased or may change and the**

Commented [JEL20]: DTE comment – this would be performed by the TO, the utility can request this study be conducted but doesn't have the capability or information to perform it

resulting impacts to the local clearing requirement.

h) **Any transmission studies that support the resource plan proposed by the utility.**

i) **Include an analysis of transmission costs for access to out of state resources conducted by either the RTO, transmission owner(s), and/or utility.**

j) **Provide RTO reports or web links to report locations that contain information relied upon to support model assumptions or other IRP decisions.**

Commented [JEL21]: DTE comment – this would be performed by the TO, the utility can request this study be conducted but doesn't have the capability or information to perform it

Commented [ANL22]: DTE Request: Could you clarify what this is referring to? Is this referring to the que?

XIII) 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; and
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.

XIV) 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 ~~generation~~ resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. 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 of eachresource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned **resources** ~~generation~~;
b) New build:
   i. New generation technology and operating assumptions;
   ii. New generation development costs;
   iii. New energy integration of storage technology and operating assumptions, **including both long and short duration storage**;
   iv. New energy storage development costs;
   v. **Development costs and operating assumptions for combinations of resources constructed as a single facility.**

Commented [ANL23]: DTE Comment: DTE requests clarification on what is meant by development costs

c) Distributed generation:
   i. Solar photovoltaic (including solar plus storage);
   ii. Biogas;
   iii. Energy storage;
   iv. Other distributed generation;
d) Market capacity purchases:
   i. Regional market supply outlook;
   ii. Availability of market capacity;
   iii. Market capacity price assumptions;
e) Long-term power purchase agreements;
f) Transmission resources:
   i. Overview;
   ii. Existing import and export capability;
   iii. Transmission network upgrade assumptions for the IRP; and
   iv. Import and export impact on resource strategy.

XV) 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 necessarily exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination);
b) ~~Scenario and sensitivity~~ Results **for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that** include annual incremental revenue requirements, present value of annual incremental revenue requirements and incremental 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;
c) ~~Business as usual/reference~~ **Base** case portfolio~~s~~ options to be selectedfrom;
d) Analysis of IRP results; and
e) Risk assessment **presented with graphics and data that illustrate stochastic risk analysis results in such a way that the probability distributions are clearly conveyed 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.**

XVI) **Proposed Resource Plan**:

Include a detailed description of:

a) The type of energy resource 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 power purchase agreements;
c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of

Commented [JEL24]: DTE comment: Added incremental for clarity here and in other instances. The Revenue Requirement reported by the capacity expansion model is typically an incremental rev req and does not include the full rev req on existing assets.

natural gas to any new generation facility; and

d) How the utility will meet local, state, and federal laws, rules, and regulations under the proposed course of action.

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

a) Strike an appropriate balance between the various planning objectives specified;
b) Utilize renewable, **storage** and demand-side resources to comply with existing laws and goals and, in the judgment of the utility, are consistent with the public interest and achieve state energy policies; and
c) In the judgment of the utility, the **proposed resource plan** ~~preferred plan~~, in conjunction with thedeployment of demand response measures, has sufficient resources toserve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the **proposed resource plan** ~~preferred 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 net present value revenue requirement 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 net present value revenue requirement of the utility's proposed **resource** plan and **any** alternative resource plans including the alternative resource plans

resulting from theCommission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.

e) **A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning such as distributed energy resources 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.**

f) **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.**

g) **A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.**

XVII) Rate Impact and Financial Information:

Projected year-on-year impact of the proposed **resource plan** ~~course of action~~ (and other feasible options) for the periods covered by the plan, covering the followingaccounts:

a) Incremental Revenue requirement;
b) Rate base;
c) Plant-in-service capital accounts;
d) Non-fuel, fixed operations and maintenance accounts;
e) Non-fuel, variable operations and maintenance accounts;
f) Fuel accounts;
g) Emissions cost;
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

Commented [LKM25]: DTE Comment: Added incremental for clarity

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 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) Net present value of incremental revenue requirements for the plan;
g) Nominal incremental revenue requirements by year; and
h) Average system rates per kWh by year.

XVIII) Environmental **Considerations and Environmental Justice**:

Describe how the utility's **resource plan and any alternative resource plans presented in the application** ~~proposed IRP~~ 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) **If the Company is proposing retirement of an existing resource, clearly identify the capital cost for environmental regulations and other capital investments in the facility that is avoided capital cost, becomes cost of removal, or is truly avoidable cost.**

~~d) Provide an annual projection of the following emissions for the study period differentiating between existing and new resources within the proposed IRP:~~

~~i. Tons of sulfur oxides;~~
~~ii. Tons of oxides of nitrogen;~~
~~iii. Tons of carbon dioxide;~~
~~iv. Tons of particulate matter; and~~
~~v. Pounds of mercury.~~

~~e) Provide the total projected emissions of the items listed below through the study period for the utility's proposed plan, as well as the scenarios identified in the MIRPP as approved in Case No. U-18418, or modified by Commission order:~~

~~i. Tons of sulfur oxides;~~
~~ii. Tons of oxides of nitrogen;~~

Commented [ANL26]: DTE Response: DTE supports a smaller subgroup that will focus on Environmental considerations and EJ being formed to work through this section with stakeholders and EGLE

Commented [ANL27]: DTE Comment: Please provide an example for reference

~~iii. Tons of carbon dioxide;~~

~~iv. Tons of particulate matter; and~~

~~v. Pounds of mercury.~~

f) **Hold a technical conference with MPSC and EGLE staff within 30 days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.**

g) **Identify, quantify, and provide testimony that compares the expected changes in criteria pollutants, mercury, VOCs, and GHG emissions of the proposed resource plan ~~in the base case~~ to the previously approved build plan ~~in the base case~~. Illustrate how the proposed resource plan will comply with state and federal GHG goals.[2],[3] The previously approved build plan may include a refresh that takes into account the updated load forecast and additional resources to meet any increase in load, but leave the previous base generation assumptions in place. The Company will use a proxy to determine the emissions from MISO purchases and will run the base case scenario with two build plans: the previously approved base build plan and the proposed resource plan.**

h) **Analyze multiple build plans, including the proposed resource plan and the optimal build plan from the MIRPP required scenarios to identify and both qualitatively and quantitatively assess the potential impacts to vulnerable communities. This assessment should address water quality, water use, water discharge, waste disposal, air emissions, public health, climate, environmental justice, early retirement, and other considerations that were taken into account in the Company's decision. The Michigan Environmental Justice Screening Tool or equivalent should be used for the identification of vulnerable areas.**

i) **Identify and assess the impact of the proposed resource plan to any non-attainment areas within the electric utility service territory and qualitatively support in testimony. Impacts should consider SO_2 and ozone, as well as their precursors NO_x and $PM_{2.5}$.**

j) **Using the areas identified as vulnerable by the Michigan Environmental Justice Screening Tool, or equivalent (see h) above) complete a more comprehensive evaluation of PM2.5 impacts to these communities, describing expected air quality impacts, including the effect of an early retirement. Conduct dispersion modeling for PM2.5 using standard permit modeling protocols and methods. The base case emissions should be used to establish a baseline modeling demonstration by which to compare the previously referenced least emitting and potential early retirement scenarios in the area where emissions are expected to occur.**

Commented [ANL28]: DTE Request: Can you provide clarification that this is referring to 30 days after the filing is made?

Commented [JEL29]: DTE comment – This assumes that the proposed plan has specific sites selected for resources, especially in the mid to long-term. The IRP determines an optimized plan but doesn't assume to have specific locations selected making this difficult to quantify

Commented [JEL30]: DTE comment – request clarification on what "base case" is referring to, suggest removing reference to base case

Commented [ANL31]: DTE Request: Could you provide clarification and examples on how to illustrate the proposed resource plan complies with the state and federal GHG goals? Are you requesting a utility to show that reductions meet the economy-wide goals or does the utility need to show compliance another way? Can a demonstration be that a plan meets the federal goal at a company level (e.g. 50% by 2030 and net zero by 2050)?

Commented [ANL32]: DTE Comment: could you provide clarification if we are required to look at generating sources we have within a certain distance of a vulnerable area and do a comparison if the source wasn't there?

Commented [JEL33]: DTE comment - Rather than require dispersion modeling as the method to compare impacts, introduce it as an example of how it can be done. If the utility analysis shows that this comparison of impacts can be completed using emissions data, why conduct air dispersion modeling.

[2] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) on September 23, 2020, 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.

[3] 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.

k) **Include metrics to quantify health benefits related to air emission reductions in the scenarios listed above. The following EPA reports and tools provide guidance and are listed in order of preference: the Environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the "Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool" and "Quantifying the Emissions and Health Benefits of Energy Efficiency and Renewable Energy".)".**

l) **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, the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period.**

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

c) Any modeling input and output files used in developing the application, supporting testimony, **resource plan and any alternative plans** ~~and IRP~~. 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-dependentbinary format should be made available to parties that obtain a license;

d) Cost data**,** ~~and~~ estimates**, and co-benefit analyses** that were used in the resource screening process **or in any other way to** ~~**deteriminedetermine**~~**determine** **resource selection of** ~~to evaluate~~ each electric resource that was considered either individually or in combination with other resources **constructed as a single facility**, including **distributed energy resources, storage, and** renewable **energy resources.** ~~alternatives, such as solar, wind, or solar plus battery~~

Commented [JEL34]: DTE comment - Request clarification. Does "include metrics to quantify health benefits" using the tools reference actually mean "quantify health benefits"? that would be more clear instruction if that is intention vs. just providing inputs for someone else use to quantify.

Commented [ANL35]: DTE Request: see comment above. Could you clarify how to illustrate compliance with the state and federal goals?

Commented [JEL36]: DTE comment - wording

~~storage~~;

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

f) 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 proceeding;

g) 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;

h) 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 utilities generation fleet;

i) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP;

j) A comparison of total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the **base**~~business as usual~~ case;

k) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates;

l) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus battery storage, and such cost estimates for all alternative proposals, solicited or unsolicited, received by the utility;

m) Electricity market forecasts utilized

n) **A stacked bar chart that includes all existing resources and proposed resources color designated by resource type in each of the planning years with the inclusion of a line representing expected load over the length of the planning period.**; and

o) Other documents and data underlying the IRP analysis.

DRAFT Michigan Integrated Resource Planning Parameters for December 16th Stakeholder Meeting

II. Energy Waste Reduction Potential Study

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

The statewide assessment of energy waste reduction (EWR) potential was conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[1]

Scenario #1 - Reference: Estimates of achievable potential calibrated to 2021 or more recent, where applicable, total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual or more recent, where applicable, achievements. Key assumptions include non-low-income measure incentives of 40% of incremental cost (low-income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

Scenario #2 - Aggressive: Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

Scenario #3 - Carbon Price: Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations. Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

This EWR potential study has resulted in updated, expanded, and improved

Commented [ANL1]: DTE Comment: Suggest making this statement more flexible by referencing the most recent statewide assessment of EWR and application where applicable (based on modeling timing). What if there is a more recent EWR potential study available at the time a utility files?

Commented [ANL2]: DTE Comment: Rather than a link to the specific document, the Commission could provide a link to a folder on its web site which contains the 2021 study and to which any subsequent study would be added.

Commented [ANL3]: DTE Comment: DTE made suggestions to revise specificity of section

[1] MI EWR Potential Study, https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Report_-_Final_735360_7.pdf, Retrieved December 8, 2021.

information on the Michigan customer base, and the potential for energy and demand reductions possible through EWR programs and initiatives by building upon previous studies, with the addition of natural gas potential and analysis of the Upper Peninsula. While much EWR potential remains, there are unique challenges in Michigan in realizing this potential over the 20-year study period. The potential study incorporates these real factors into the analysis by using primary research findings, Michigan baseline study data, and historical and expected program achievements, to estimate efficient measure and fuel type saturations, as well as calibration targets.

III. Demand Response Potential Study[2]

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

The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

~~To comply with Section 6t, Staff determined that the assessment for use of demand response~~

Commented [ANL4]: DTE Comment: We have the same concerns here with limiting to the 2021 study. If there is a more recent DR potential study available at the time the utility files, it should be able to use the more recent study.

[2] ~~See supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf~~ **https://www.michigan.gov/mpsc/0,9535,7-395-93308_94792-552726--,00.html.**

~~programs would best be comprised of two parts: a technical study[3] and a market assessment.~~[4]

IV. 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.

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

Federal rules and laws:

Commented [ANL5]: DTE Comment: suggest aligning and updating this section with EGLE due to recent developments

Clean Air Act – The Clean Air Act is a United States federal law designed to control air pollution on a national level. The Clean Air Act 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 Clean Air Act requires the United States Environmental Protection Agency (USEPA) to set NAAQS for six criteria pollutants that havethe potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standards are set at a level that is protective of 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 pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[5]

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, forward progress in controlling emissions within their boundaries. Those that do not abide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject to **US**EPA 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 **US**EPA for approval into the State Implementation Plan, and ensuring attainment occurs bythe 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 **US**EPA strengthened the primary NAAQSfor SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

~~[3] Demand Response Potential Study, http://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf.~~

~~[4] Demand Response Market Assessment, http://www.michigan.gov/documents/mpsc/MI_Demand_Response_Market_Assessment_20170929_602432_7.pdf.~~

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

A federal consent order set deadlines for the **US**EPA to designate nonattainment areas in several rounds. Round one designations were made in October 2013, based on violations of the NAAQS at ambient monitors. A portion of Wayne County was designated non-attainment.T~~he area must attain the NAAQS by October 2018. The state's attainment plan was due to theEPA by April 2015~~.

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into ~~compliance~~ attainment with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan for the non-attainment area, the action of which is still underway.

Round two designations were based on modeling of emissions from sources emitting over 2000 tons of SO_2 per year. A portion of St. Clair County was designated nonattainment in September 2016. ~~Attainment must be achieved by September 2021, and the state's attainment plan is due to the EPA by March 2018~~.

To better understand the quality of the air in the non-attainment area, ~~tow~~two monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020, waiving the SIP requirement for the area. Upon shutdown of the St. Clair Power Plant in 2022~~2~~, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations **were to** ~~**ill**~~ address all remaining undesignated areas by December 31, 2017. The **US**EPA 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 **US**EPA 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** ~~intended to also be~~ designated as unclassifiable/attainment.

Ozone Non-Attainment 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 non-attainment 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

Commented [ANL6]: DTE Suggestion: remove "compliance" and insert "attainment"

Commented [ANL7]: DTE Suggestion: remove "tow" and insert "two"

Commented [ANL8]: DTE Comment: Revise to "2022"

Commented [ANL9]: DTE Comment: update for approval by EPA in December

Muskegon and one full county, Berrien were found to have design values[6] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also more stringent requirements for major source air permits, including lowest achievable emission rate conditions and offsets for new emissions of the ozone precursors of nitrogen oxides and volatile organic compounds. To attain the standard, monitoring values over the three-year time period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

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 Clean Air Act for the ozone standards and fine particulate matter standards. CSAPR is a cap and trade rule which governsthe emission of SO_2 and NO_x from fossil-fueled electric generating units through an allowance- based program. Under this program, NO_x is regulated on both an annual basis and during the ozone season (~~May~~ **April** through **October** ~~September~~). Each allowance (annual or ozone) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. ~~Recently,~~ The **US**EPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. ~~In the future,~~ The state ~~will have~~ **currently has** Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the Revised CSAPR rule update for the 2008 ozone NAAQS. Starting in the 2021 ozone season, the rule required additional emissions reductions of NO_x from power plants in 12 states, including Michigan.

~~**EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040**~~**.**

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the **US**EPA toadopt maximum available control technology standards for hazardous air pollutants. 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. Existing sources were required to comply with these standards by April 16, 2015. Some individual sources were granted an additional year, at the discretion of the Air Quality Division of **EGLE** ~~the MDEQ~~. In June 2015, the United States Supreme Court found that the **US**EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the **District of Columbia** Circuit Court of Appeals ruled that MATS may be enforced as the **US**EPA modifies the rule to comply with the United States Supreme Court decision. ~~The deadline for MATS compliance forall electric generating units was April 16, 2016.~~

In May 2020, USEPA corrected flaws in the 2016 Supplemental Co~~tts~~sts Finding for the

[6] The designe value is the three year average of the 4th highest 8-hour ozone value)

Commented [ANL10]: DTE Comment - EGLE recently submitted a redesignation request for the SE Michigan nonattainment area to EPA based on the 2019-2021 ozone season data.

Commented [ANL11]: DTE Comment: The rule didn't necessarily require emissions reductions. The rule lowered the allocation of allowances for EGUs in the 12 states.

Commented [ANL12]: DTE Suggestion: DTE suggests deleting this – not applicable to planning parameters

Commented [ANL13]: DTE Comment: this is applicable to EGUs, not all facilities

Commented [ANL14]: DTE Comment: DTE suggests deleting this. Redundant to above

Commented [ANL15]: DTE Suggestion: Suggest rephrasing the first sentence to "In May 2020, USEPA amended the MATS rule as a result of the 2015 US Supreme Court decision."

MATS rule consistent with the 2015 United States Supreme Court decision. The agency also completed the CAA required residual risk and technology review (RTR) for MATS. Power plants are already complying with the standards that limit emissions of mercury and other hazardous air pollutants (HAPs), and this final action leaves those emission limits in place and unchanged.

Clean Air Act 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 Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the **US**EPA finalized a NSPS that established standardsfor emissions of carbon dioxide for newly constructed, modified, and reconstructed fossil-fuel fired electric generating units. There are different standards of performance for fossil fuel-fired steam generating units and fossil fuel-fired combustion turbines.[7]

Clean Air Act Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the Clean Air Act requires the **US**EPA to establish standards for certain existing industrial sources. The final Clean Power Plan, promulgated on October 23, 2015, addressed carbon dioxide emissions from electric generating units. The Clean Power Plan established interim and final statewide goals and tasked states with developing and implementing plans for meeting the goals. Michigan's final goal was to reduce carbon dioxide emissions by 31 percent from a 2005 baseline by 2030.[8]

Commented [ANL16]: DTE Suggestion: include "dioxide"

On February 9, 2016, the United States Supreme Court issued five orders granting a stay of the Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the **US**EPA to review the Clean Power Plan and the standards of performance for new, modified, and reconstructed electric generating units (section 111(b) rule). As a result, the Department of Justice filed motions to hold those cases in abeyance pending the **US**EPA's review of both rules, including through the conclusion of any rulemaking process thatresults from that review. ~~The Clean Power Plan does not currently affect Michigan utilities, however due to the EPA's 2009 endangerment finding on greenhouse gases, utilities should address their future anticipated greenhouse gas emissions~~.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon dioxide emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it back to the USEPA

Commented [ANL17]: DTE Comment: This should be 2019

Commented [ANL18]: DTE Suggestion: insert "dioxide"

[7] 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.
[8] The 111(d) rule can be viewed in full here: https://www.federalregister.gov/documents/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West ~~Verginia~~Virginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer 2022.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current carbon reduction goals ~~on carbon neutrality~~ at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon reduction ~~carbon neutrality~~ goals in mind.

Commented [ANL19]: DTE Comment: correct to Virginia

Commented [ANL20]: DTE Comment: Remove "electric generating units" as it is defined above in the paragraph and keep EGU

Commented [ANL21]: DTE Comment: Change to "carbon reduction"

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 carbon dioxide underground. Facilities calculate their emissions using approved methodologies and report the data to the **US**EPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The **US**EPA conducts a multi-step verification process to ensure reported data is accurate, complete and consistent. This data is made available to the public in October of each year through several data portals.

Boiler Maximum Achievable Control Technology – The Boiler MACT establishes national emission standards for hazardous air pollutants 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 Clean Air Act 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. 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, nitrogen oxides, sulfur dioxide, 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. A BART analysis considered five factors as part of each source-specific analysis: 1) the costs of compliance, 2) the energy and non-air quality environmental impacts of compliance, 3) any existing pollution control technology in use at the source, 4) the remaining useful life of the source, and 5) the degree of visibility improvement that may reasonably be anticipated to result from use of such technology. For fossil-fueled electric generating plants with a total generating capacity in excess of 750 MW, states must use guidelines promulgated by the **US**EPA. In 2005, the **US**EPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the **US**EPA issued a final rule setting revised and clarifying requirements for periodic updatesin state plans. The next periodic update **was** ~~is~~ due July 31, 2021. **EGLE has submitted the periodic update and it is currently being reviewed by USEPA.** There are two Class 1 areas in Michigan: Seney National Wildlife Refuge and Isle Royal National Park. Michigan also has an obligation to eliminate the state's contribution to impairment in Class 1 areas in other states.

Resource Conservation and Recovery Act – The Resource Conservation and Recovery Act (RCRA) gives the **US**EPA 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.

In April 2015, the **US**EPA established requirements for the safe disposal of coal combustion residuals **(CCR)** produced at electric utilities and independent power producers. These requirements were established under Subtitle D (Non-hazardous solid waste) of RCRA and apply to coal combustion residual landfills andsurface impoundments. Michigan electric utilities must comply with these regulations.

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 **US**EPA promulgated rules under Section 316(b) of theClean 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

Commented [ANL22]: DTE Suggestion: Include "(Non-hazardous solid waste)"

Commented [ANL23]: DTE Comment: Suggest expanding this section to include a little more background and detail similar to the ELG rule. At a minimum revised in October 2016, July 2018, September 2020, and November 2020, with a brief descriptions of those changes. Also should consider adding a brief description of EPA's intent to issue rules on Legacy CCR Impoundments a design intake flow greater than two million gallons per day that use at least twenty-five percent of the water withdrawn from the surface waters of the United States for cooling purposes.

In 2001, the **US**EPA promulgated rules specific to cooling water intake structures at new facilities. Generally, new Greenfield, stand-alone facilities are required to construct the facility to limit the intake capacity and velocity requirements commensurate with that achievable with a closed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulations for existing facilities were promulgated in August 2014. These rules were also challenged and undergoing judicial review. 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. The rules do not specify national BTA standards for minimizing entrainment mortality, but instead require that **EGLE** ~~the MDEQ~~ establish the BTA entrainment requirements for a facility on a site-specificbasis. These BTA requirements are established after consideration of the specific factors spelled out in the rule. Facilities with actual flows in excess of 125 million gallons per day must provide an entrainment study with its National Pollutant Discharge Elimination System (NPDES) permit application. 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** ~~the MDEQ~~ 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 limitations 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. Multiple petitions for review challenging the regulations were consolidated in the United States Court of Appeals for the Fifth Circuit on December 8, 2015. On April 25, 2017, the **US**EPA issued an administrative stay of the compliance dates in the ~~effluent limitations guidelines~~ **ELGs** and standards rule that ha**d** not yet passed pending judicial review. In addition, the **US**EPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the **US**EPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the **US**EPA provided notice that it ~~will~~ **would** conduct a rulemaking to ~~potentially~~ revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash **(BA)** transport water and flue gas desulfurization wastewater **(FGD)**. **The USEPA published the regulations on October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of**

Commented [ANL24]: DTE Comment: Add "US"

these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the USEPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the USEPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. USEPA intends to publish the proposed rulemaking for public comment in the fall of 2022. ~~The EPA will provide notice and an opportunity for comment on any proposed revisions to the rule and will notify the United States Court of Appeals that it seeks to have challenges to those portions of the rule severed and heldin abeyance pending completion of the rulemaking.~~ On September 18, 2017 the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG **was** ~~is~~ November 1, 2020. ~~, while the latest compliance date of December 31,2023 remains unchanged.~~

State Rules and Laws:

National Pollutant Discharge Elimination System (NPDES Program) – The NPDES permit program controls the discharge of pollutants into surface waters by imposing effluent limitations to protect the environment. Authority to administer the program was delegated by EPA to Michigan in 1973 and now operates under Part 31 of Act 451. EGLE manages the NPDES permit program and issues permits to comply with the Federal SEEG technology-based ELGs and standards for the steam electric power generating industry.

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 electric generating units must choose one of three methods to comply with the emission limits and any new electric generating unit 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 (MEPA) – Part 17 of Michigan's Natural Resources and Environmental Protection Act (NREPA), 1994 PA 451. Under MEPA, the attorney general 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 coal ~~combustion residuals (~~CCR~~)~~ as a solid waste. It requires any CCR that will 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

Commented [ANL25]: DTE Comment: Add "US"

Commented [ANL26]: DTE Comment: Suggest including a general introduction here to help provide understanding as to how the State environmental program is organized. E.g. "**Michigan Environmental Laws -**
Most of Michigan's environmental laws were consolidated into the Natural Resources and Environmental Protection Act, 1994, PA 451, as amended (Act 451). Act 451 is organized into Parts."

Commented [ANL27]: DTE Comment: Suggest adding this section to tie to the Federal rule action, and financial assurance and post-closure care for a 30-year period. The disposal facility is required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care period.

The disposal facility is required to maintain the 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 Act was passed, which included an amendment to Section 4005 ofRCRA providing a mechanism to allow states to develop a state permitting program for regulationof CCR units. **Under the amendment, u**~~U~~pon approval of a state program by USEPA, 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 the majority of the RCRA regulations whould 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 the majority of the RCRA rule, including the regulation of CCR surface impoundments used for storage. Michigan's request for state program approval is currently under review by the USEPA.** ~~Michigan is in the process of developing a permit program for submittal to the EPA.~~

Commented [ANL28]: DTE Comment: Suggest inserting "by USEPA"

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

A list of federal and state environmental regulations, laws and rules formally proposed have been identified as required by Section 6t (1) (d):

Ozone Nonattainment Areas – Following the 2020 ozone season, design values for ozone monitors located in all four of the nonattainment areas did not demonstrate attainment with the 2015 ozone NAAQS; therefore, it is anticipated that the nonattainment areas will be reclassified by EPA in February 2022 from marginal to moderate nonattainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional elements to reduce emissions to attain the standard. Required moderate nonattainment planning elements include reasonably available control technology, reasonable further progress, a motor vehicle inspection and maintenance program (southeast Michigan only due to the population threshold), and an attainment demonstration.

Commented [ANL29]: DTE Comment: Suggest moving this section to the ozone NAAQs section above. It makes it seem that these are separate.

~~The ozone NAAQS was revised by the **US**EPA in 2015 from 75 ppb to 70 ppb. Nonattainment designations were to be made by October 2017. In June 2017, the **US**EPA announced a decision to delay making designations by one year. More recentlyon August 2, 2017, the **US**EPA withdrew its plan to delay designations. Michigan is expecting ten counties, or portions of counties, to be designated nonattainment, including Wayne, Oakland, Macomb, St. Clair, Livingston, Washtenaw, and Monroe in Southeast Michigan and Muskegon, Allegan, and Berrien in West Michigan. Deadlines and requirements for ozone nonattainment areas are dependent on the classification assigned to the nonattainment area. All ozone nonattainment areas in Michigan are expected to be classified "Marginal". This classification would establish an attainment deadline of 2020 or 2021 depending on the date of designation, and an attainment plan submittal deadline of 2020 or 2021. In addition to the requirement to attain by the deadline, there will also be more stringent requirements for major source air permits, including lowest achievable emission rate conditions and offsets for new emissions of the ozoneprecursors of~~

~~nitrogen oxides and volatile organic compounds.~~

In September 2021, it became apparent that current ozone data in southeast Michigan was displaying values that could potentially allow for attainment with the 2015 standard. Meetings were scheduled ~~schedlued~~ with the USEPA and a redesignation request was drafted. Following the closure of the ozone season on October 31, 2021, design values were calculated and it was determined that southeast~~soueast~~ Michigan had attained the standard using years 2019, 2020, 2021 ozone season data. The redesignation was put out for public comment in November 2021~~2120~~, and it is anticipated that the request~~requiest~~ will be submitted to USEPA in December 2021. Should USEPA approve the redesignation request~~requiest~~, southeast Michigan will become maintenance for the 2015 ozone standard.

Commented [ANL30]: DTE Comment: Wording

Commented [ANL31]: DTE Comment: Wording

Commented [ANL32]: DTE Comment: Year revision to 2021

Commented [ANL33]: DTE Comment: Wording

Commented [ANL34]: DTE Comment: Update wording to reflect that the request was recently submitted

Commented [ANL35]: DTE Comment: Wording

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** ~~utilities~~ generation fleet, and include the relevant future compliance costs within the IRP model. Review and approval of an electric utility's integrated resource plan by theMichigan Public Service Commission does not constitute a finding of actual compliance with applicable state and federal environmental laws. Electric utilities that construct and operate a facility included in an approved integrated resource plan remain responsible for complying with all applicable state and federal environmental laws.

V. 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 local clearing requirements 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 (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.[9] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins ~~2018~~ **2022**through ~~2027~~ **2031**" for the entire footprint.[10] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[11] The local reliability requirement is a measure of the planning resources required to be physically located inside a local resource zone without considering any imports from outside of the zone in order to meet the reliability criterion

Commented [LKM36]: DTE comment - Suggest deleting, the years will quickly be obsolete as this report is updated over time and are not needed with the rest of the description.

[9] MISO **2022-2023** ~~2018 – 2019~~ Loss of Load Expectation Study Report published on **November 1, 2021** ~~October 2017~~, ~~https://www.misoenergy.org/Library/Repository/Study/LOLE/2018%20LOLE%20Study%20Report.pdf~~ **https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.**

[10] Three of the next ten years planning reserve margins are modeled by MISO and the remaining of the ten years are interpolated and reported in the MISO Loss of Load Expectation Study.

[11] MISO models the local reliability requirement for the prompt year, one of the future years in between year 2 and year 5, and one future year in between year 6 and year 10.

of one day in ten years LOLE. The MISO Local Clearing Requirement is defined as "the minimum amount of unforced capacity that is physically located within the Zone that is required to meet the LOLE requirement while fully using the Capacity Import Limit for such."[12] The Local Clearing Requirement for each zone is reported annually with the MISO planning resource auction results in April.[13]

For the southwest corner of the Lower Peninsula, in PJM's territory,[14] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[15] 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 local resource zones. PJM publishes a Reserve Requirement Study[16] 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 integrated resource plans 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 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 utilityIRP filings should be consistent with the requirements of the State Reliability Mechanism underSection 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiatedto implement these provisions.

[12] Federal Energy Regulatory Commission Electric Tariff, Module E-1, 1.365a. 1.0.0.

[13] MISO Planning Resource Auction results, April-**2021** ~~2017,~~ ~~https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf.~~ **https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf**

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

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

[16] PJM Reserve Requirement Study, October ~~2017~~ **2021**, ~~http://www.pjm.com/-/media/committees-groups/committees/mrc/20171026/20171026-item-05-2017-irm-study.ashx.~~ **https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx**

VI. Modeling Scenarios, Sensitivities and Assumptions

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

For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, ~~three~~ **two** modelingscenarios are required. ~~There is a total of four unique scenarios included in this IRP parametersdocument; the applicability of each is described within the narrative of each particular scenario~~.Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located inMichigan that already file multistate IRPs in other jurisdictions. Due to the provisions in PA 341 Section 6t (4) regarding multistate IRPs, Northern States Power-Wisconsin and Indiana Michigan Power Company are intentionally excluded from the explicit requirement to model theoutlined scenarios. However, the multistate utilities are encouraged to include the provisions included in each scenario. The Commission may request additional information from multistate utilities prior to approving an IRP pursuant to Section 6t (4) of PA 341.

Scenario 1: Base Case

~~(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)~~

~~The existing generation fleet (utility and non-utility owned) is largely unchanged apart from new units planned with firm certainty or under construction. No carbon regulations are modeled,although some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals, as well as economics.~~

This scenario reflects substantial achievement of state and utility announcements. While Scenario One incorporates 100% of utility integrated resource plan (IRP) announcements throughout the MISO footprint, state and utility goals and announcements that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these goals and announcements at their proposed respective timelines. Emissions decline as driven by state goals and utility plans throughout the MISO footprint creating a trajectory of 63% reduction in carbon emissions by 2039 from the baseline year of 2005. This scenario assumes that demand and energy growth are driven by existing economic factors, with small increases in EV adoption, resulting in an annual energy growth rate of 0.5%.(cite 2021 MISO Futures Report)

- Natural gas prices utilized are consistent with **the Reference Case** ~~business as usual~~ projections ~~as projectedin~~ **from** the United States Energy Information Administration's (EIA) most recent Annual EnergyOutlook reference case.[17]
- **Moderate EV adoption and customer electrification result in moderate f**ootprint-wide[18] demand and energy growth rates **remain at historic 3-year average levels for the first 3 years of the planning horizon, then are blended for 2 years to result at**

[17] 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 also including delivery costs from Henry Hub to the point of delivery.

[18] Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State ofMichigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

Commented [ANL37]: DTE Comment:
Please define exactly how the MISO futures are to be used. Which parameters from the MISO futures are to be used in the Utility's Capacity expansion models?

- The retirements
- The additions
- The EV adoption rate
- Other Electrification assumptions
- The annual energy growth rate
- other items

Are the specified MISO futures parameters to be applied to all entities modeled including the Utility, for everyone besides the Utility, or for rest of the MISO zones without the utility? In addition, the study will be updated yearly, how will the new assumptions be incorporated into the IRP process? Yearly updates could vary quite a bit based on the assumptions; how will this be addressed? How are assumptions used for MISO applied to each utility's service territory?

The Utility's retirements and additions from the MISO Future should not be prespecified in the capacity expansion model. They could possibly be used to generate a market in a larger footprint model, however all Utilities have different modeling processes, so this would likely not work for all Utilities.

DTE would like to consider the other comments that come in on how the MISO Futures would be used and participate in additional discussions on this important topic. We will likely have more comments and recommendations after additional discussions and recommendations are determined.

Commented [ANL38]: DTE Comment: Could you provide clarification on this subject? It is unclear what is considered a legislative order.

Commented [JEL39]: DTE Comment: It's unclear what 0.5% represents and is addressed in the bullet below

the load growth level consistent with the most recently available MISO Future 1 after the fifth year of the planning horizon; ~~remain at low levels with no notable drivers of higher growth;~~ however, as a result of low natural gas prices, industrial production and industrial demand increases.

- ~~Low natural gas prices and low economic growth reduce the economic viability of other generation technologies~~.
- Resource assumptions:
  - Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).
  - Resources within MI – Thermal and nuclear generation retirements in the modeling footprint are driven by a maximum age assumption, public announcements, or economics.
- Specific new units are modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), **IRP cost pre-approval**, or signed generator interconnection agreement (GIA)).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- **The plan meets current state and federal goals for greenhouse gas emissions.**[19,20]
- For all instate electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include an EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap.[21]
- ~~For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.~~
- Existing renewable energy **and storage** production tax credits and renewable energy investment tax credits continue pursuant to current law.
- **Long and short duration storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.**

Commented [ANL40]: DTE Comment: this should include a footnote to MISO Futures; how do you determine 3-year average and blending and what does this represent? Does this include EWR, etc? Suggest deleting this requirement. DTE suggests allowing each utility to determine its load forecast specific to its service territory

Commented [ANL41]: DTE Comment: should clarify that this is specific to the power industry sector only

Commented [ANL42]: DTE Comment: DTE is not aware of best practices for modeling – is there something specific this is referring to? What is meant by guidelines? In addition, how is best practice determined when considering that each model has different capabilities and applicability is not standardized?

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[19] 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.

[20] 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.

[21] For EWR cost supply curves, see the **Michigan Energy Waste Reduction Potential Study (2021-2040) Report** ~~appendices in the supplemental potential study for the Lower Peninsula~~ at this link:
~~http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf~~
https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Final_Draft_Report_732747_7.pdf

- 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 demand response programs will be determined by **the more recent state-wide** ~~their respective~~ potential studi~~es~~y, where applicable.
- Technology costs for solar**, storage,** and other emerging technologies decline with commercial experience.
- Existing PURPA contracts are assumed to be renewed.

Commented [ANL43]: DTE Comment: Add "more recent"

Scenario #1 Sensitivities:

1. Fuel cost projections
   (a) 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** ~~200% of the business as usual~~ natural gas fuel price projections at the end of the study period.[22]

2. Load projections
   (a) High load growth: ~~Increase the energy and demand growth rates by at least a factor of two above the base case energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base case load projection and the high load sensitivity projection,~~ A~~a~~ssume a 1.0~~5~~% increase in the annual growth rate for energy and demand for this sensitivity.
   (b) ~~**Low load growth: EV adoption and electrification are slower than expected and the demand and load growth stay at historic levels.**~~**EV adoption and electrification are slower than expected and the demand and load growth are consistent with 5 year historical growth rates prior to 2020 and the onset of COVID-19.**
   (c) If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service ~~by **2027**~~**, with a 2 year ramp up of 25% each year**~~**3**~~.

Commented [ANL44]: DTE Comment: Suggested wording changes

Commented [ANL45]: DTE Comment: Revise section

Commented [ANL46]: DTE Comment: Suggest wording change. Suggest not tying to specific years, because these IRPs could be filed between 2023 and 2027.

3. Ramp up the utility's EWR savings to at least 2.0~~5~~%[23] of prior year sales over the course of our years, using EWR cost supply curves provided in the mo~~s~~re current utility specific or Michigan statewide potential study~~,~~ where applicable ~~using EWR cost supply curves provided in the Appendix G of the 2017 supplemental potential study for more aggressive potential~~.[24] EWR savings remain high throughout the study period.

Commented [ANL47]: DTE Comment: Suggested word update

4. ~~Sensitivity allowing only natural gas fired simple cycle combustion turbines to be selected by the model.~~ **Perform a model run that optimizes the resource build that considers only legislatively mandated carbon goals and does not consider non-legislatively**

Commented [JEL48]: DTE comments – request clarification and examples of legislatively mandated

[22] **For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.**
[23] **2021 Energy Waste Reduction Potential Study, Appendix D.**
[24] **Cite appropriate part of the EWR potential study.**

mandated carbon goals.

~~**5. Out-of-State transmission congestion cost increases due to changing resource mix across the region. Assume transmission cost increases of XX%**~~

Commented [JEL49]: DTE comment – suggest deleting this. How will this be determined? Will there be a study commissioned by the MPSC from METC/ITC and/or will MISO be providing something that can be used the utilities? There is a lot going on with different transmission projects and construction timelines as well as ambiguity about what is the starting point/baseline to determine this. In addition, our model don't differentiate which zone MISO purchases come from

Scenario 2. Electrification and Decarbonization Future

This scenario incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario requires a minimum penetration of wind and solar across the MISO region consistent with the most recent MISO Future 3.[25] Energy purchases are modeled at a carbon intensity consistent with the MISO system average. Electrification drives a total energy growth by 2040 that is consistent with the most recent MISO Future 3. Utility load profiles and peak demand are adjusted to reflect the increased EV and electrification.

- Natural gas prices utilized are consistent with reference case projections as projectedin the EIA's most recent Annual Energy Outlook reference case.[26]
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they are economically selected by the model to help comply with the specified carbon reductions in this scenario.
- **EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.**
- Non-nuclear, non-coal generators will be retired in the year the age limit is reached and driven by announced retirements. Coal units will primarily be retired based upon carbon emissions and secondarily based upon economics. Nuclear units are assumed to have license renewals granted and remain online.
- Specific new units are modeled if under construction or with regulatory approval (i.e.**IRP cost pre-approval**, CON, or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- **The plan meets current state and federal goals for greenhouse gas emissions.[27,28]**
- ~~Tax credits for renewables continue until 2022 to model existing policy~~. **Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law.**

Commented [JEL50]: DTE comments – see comments on Scenario 1 – Base Case

Commented [JEL51]: DTE comment – This is an extremely aggressive assumption. It's unclear what the basis is used to determine the amounts assumed in this case and how those would be allocated to each utility's service territory. What is the intent of using this assumption in the scenario?

Commented [JEL52]: DTE comments – duplicate with below. With the significant adoption assumptions the expectation is the loadshape would change significantly. To model this MISO would need provide the loadshape assumptions or loadshape assumptions should be agreed upon and consistently applied across utilities. DTE suggests allowing each utility to determine an aggresive load forecast specific to its service territory

Commented [JEL53]: DTE comment – see above; this is also duplicative to the above statement

Commented [JEL54]: DTE comment – see above

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

[26] 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 also including delivery costs from Henry Hub to the point of delivery.

[27] 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.

[28] 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.

- ~~Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law.~~
- Technology costs for wind, solar, storage and other renewables decline with commercial experience and forecasted at levels ~~35~~ **30**% lower than in the base case.
- Non-carbon dioxide emitting resources will be increased, due to the constraint on allowable carbon emissions in the model.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by the~~ir~~ respective **state-wide** potential **study**~~ies~~.
- Existing PURPA contracts are assumed to be renewed.

Commented [ANL55]: DTE Comment: remove this bullet as it is included twice

Scenario #2 Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least ~~200% of~~ the ~~business as usual~~ **high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast** natural gas fuel price projections at the end of the study period. [29]

~~2. Load projections~~
~~High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.~~

3. ~~5~~**80**% carbon reduction in the utility's service territory, modeled as a hard cap on the amount of carbon emissions, by 2030 as a sensitivity.[30]

4. Ramp up the utility's EWR savings to at least 2.0%[31] of prior year sales over the course offour years, using EWR cost supply curves provided in the ~~2017~~2021 MI Statewide Energy Waste Reduction Potential Study or other more recent statewide potential study ~~supplemental potential study~~ for more aggressive potential.[32] EWR savings remain high throughout the study period.

5. ~~Out-of-State transmission congestion cost increases due to changing resource mix~~

Commented [ANL56]: DTE Comment: Suggest revising the language to the most recent study or future studies

Commented [JEL57]: DTE comment – see above, suggest removing

[29] For example, ~~200% of~~ the most recent **EIA AEO Low Oil and Gas Supply natural gas price** ~~EIA AEO reference case natural gas price~~ is **$8.41/MMBtu ($2019)** ~~$10.14/MMBtu ($2016)~~ **in 2040.**
[30] **Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/**
[31] **2021 Energy Waste Reduction Potential Study, Appendix D.**
[32] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, https://www.michigan.gov/documents/mpsc/MI_EWR_Statewide_Potential_Study_Final_Draft_Report_732747_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

~~across the region. Assume transmission costs increase by XX%.~~

6. ~~Carbon Price Sensitivity?~~

Commented [JEL58]: DTE comment - Suggest deleting as there is a low carbon sensitivity in #3. If desired, #3 could have a second milestone in addition to 80% by 2030, it could have XX% by 2035 as well. Hard emissions caps are typically met in models by establishing a shadow price for CO2, so #3 and #6 are very similar and could be handled together in one sensitivity instead of two.

VII. 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
6 - Natural Gas Price *nominal dollars $/MMBtu*	• Forecasts utilized should align with scenario and/or sensitvity descriptions; Gas prices should include transportation costs.	• NYMEX futures (applicable for near-term forecasts only) • 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 sensitvity 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/Annual Reports • 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 sensitvity descriptions.	• If utility-specific data is utilized, it should be justified and made available to all intervening parties.
9 - Energy Waste Reduction Savings *MWhs*	Base Case: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to load forecast. • For non-incentive earning electric utility, mandated annual incremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should be met through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR **Base Case** ~~Business as Usual~~ Sensitivities: • For savings beyond mandate, incorporate EWR as an optimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.5% over the course of four years, using EWR Cost Supply Curves provided in the 2017 Supplemental Potential Study for More Aggressive Potential (e.g., with 100% incremental cost of incentives, no cost cap and emerging technologies assumptions.) • Consider load shape of EWR measures so on-peak capacity reduction associated with EWR can be reflected.	• Utility EWR plan and reconciliation filings • 2020 EWR Potential Studies for Consumers Energy and DTE Energy • 2020 Lower Peninsula EWR Basic Potential Estimate • 2020 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2020 Lower Peninsula EWR Cost Supply Curves

Commented [ANL60]: DTE Comment: This section needs to list the "2021 MI Statewide EWR Potential Study or more recent study, where applicable"

Commented [ANL59]: DTE Comment: Should be updated and align with above.

Revise to "Ramp up EWR savings at least 2.0% over the course of four years, using EWR Cost Supply Curves provided in the 2021 MI Statewide Energy Waste Reduction Potential Study or more recent, where applicable…"

10 - Energy Waste Reduction 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 ~~2016/2017~~2021 MI Statewide or more recent, where applicable Potential Stud~~ies~~y and Supplemental Modeling reflecting aggressive and cost effective program savings goals.	• 2016 EWR Potential Studies for Consumers Energy and DTE Energy • 2020 Lower Peninsula EWR Basic Potential Estimate • 2020 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2020 Lower Peninsula EWR Cost Supply Curves
11 - Demand Response 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/VAR optimization). • Technical, economic and achievable levels of demand response as applicable to the scenario.	• As defined by ~~2017 Demand Response Potential Study~~ **2021 Demand Response Potential Study**
12 - Demand Response 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 ~~2017 Demand Response Potential Study~~ **2021 Demand Response Potential Study**
13 - Renewable Capacity Factors		• 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, must be justified and made available to all intervening parties.
15 - Other/Emerging Alternatives	• Changes to operation guides • Options which improve reliability (SVC, HVDC, volt/VAR) • 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 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, combined heat and power, pumped hydro storage, voltage optimization) • Behind-the-Meter (customer BTM) Generation (e.g., solar photovoltaic (PV), biogas (including anaerobic digesters), combined heat and power (combustion turbine, steam, reciprocating engines), customer-owned backup generators, microturbines (with and without cogeneration), fuel cells (with and without cogeneration), small-scale 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.
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must be provided to all intervening parties.

Commented [ANL61]: DTE Comment: Revise section

Commented [ANL62]: DTE Comment: Insert "2021 MI Statewide EWR Potential Study or more recent, where applicable"

Commented [ANL63]: DTE Comment: Add "or more recent, where applicable" to the 2021 Demand Response Potential Study

Commented [ANL64]: DTE Comment: Add "or more recent, where applicable" to the 2021 Demand Response Potential Study

VIII. Additional IRP Requirements and Assumptions

1. Utility-specific assumptions for discount rates, weighted average cost of capital and other economic inputs should be justified and the data shall be made available to all parties.

2. Prices and costs should be expressed in nominal dollars.

3. The capacity import and export limits in the IRP model for the study horizon should be determined in conjunction with the applicable RTOs and transmission owners resulting from the most current and planned transmission system topology. Deviations from the most recently published import and export limits should be explained and justified within the report.

4. Environmental benefits and risk must be considered in the IRP analysis.

5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, as well as storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled over the planning period. Factors such as geographic location with respect to wind or solar resources and data sources that focus specifically on renewable resources should be considered in the determination of initial capital cost and production cost (life cycle/dispatch).

6. Models should account for operating costs and locational, capital and performance variations. For example, setting pricing for different tranches if justified.

7. 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.

8. The IRP model should optimize ~~the~~ incremental EWR and renewable energy to achieve the 35% goal. However, the model should not be arbitrarily restricted to a 35% combined goal of EWR and renewable energy. Exceeding the combined EWR and renewable energy goalof 35% by 2025 shall not be grounds for determining that the proposed levels of peak load reduction, EWR and renewable energy are not reasonable and cost effective.

Commented [ANL65]: DTE Comment: DTE suggested change

9. 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.

10. Prior to modeling the **Base Case and the Electrification and Decarbonization scenarios** ~~Business as Usual, Emerging Technologies, Environmental Policy, or High Market Price Variant Scenarios~~, the utilities shall consider and prescreen all of 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.

11. Consider including transmission assumptions in the IRP portfolio, such as the impact of transmission and non-transmission alternatives (local transmission, distribution planning, locational interconnection costs, environmental impacts, right of way availability and cost) to the extent possible.

12. 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.

13. 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.

14. Recognize capacity and performance characteristics of variable resources.

15. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.

16. Take into consideration existing power purchase agreements, green pricing and/or other programs.

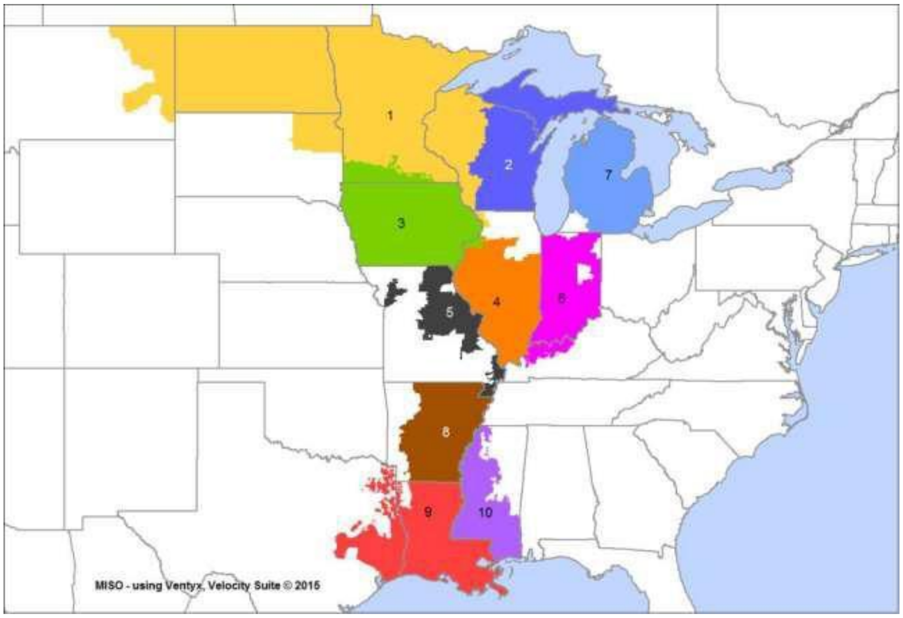
17. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the net present value of revenue requirements.

18. An analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.

Appendix A: Organization Participation List: The workgroups consisted of people from the following organizations or groups:

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones



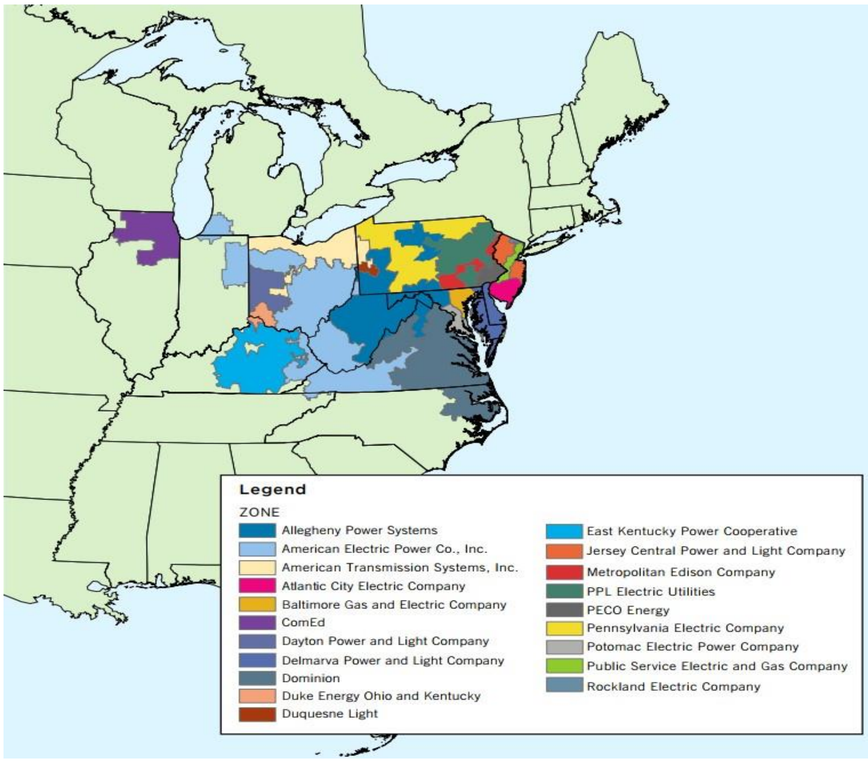
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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, within 120 days of the effective date of the amendatory act that added this section and every 5 years thereafter, commence a proceeding and, in consultation with the Michigan agency for energy, the department of environmental quality, 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, based on what is economically and technologically feasible, as well as what is reasonably achievable.

(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 shall 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, and projected load management and demand response savings.

    (iv) Any regional infrastructure limitations in this state.

    (v) The projected costs of different types of 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.

Appendix E: Environmental Regulatory Timeline - Update from Previous

Updated 8-18-2017

Comments of Douglas Jester, Managing Partner, 5 Lakes Energy In response to Staff Presentation to MiPowerGrid Advanced Planning Stakeholder Presentation on December 16, 2021

I appreciate the opportunity to comment on the Staff drafts on Integrated Resource Plan Filing Requirements and Planning Parameters. Due to the short response time over the 2021 winter holiday season, I am providing only conceptual comments and not a markup of those drafts. I am also concentrating on major issues at this stage and will likely have detailed comments on other issues at a later date.

Approaches to Emissions in IRPs

I appreciate Staff continuing to work toward appropriate consideration of the emissions of greenhouse gasses and of criteria pollutants in integrated resource planning. My comments are intended to provide a stronger analytical approach to considering emissions and the associated issues of environmental justice.

The Commission has taken, and the Staff draft continues, reasonable steps to require the projection of emissions of both greenhouse gasses and criterion pollutants for the proposed build plan in relation to the utility's previous plan. This comparison, however, is insufficient for the purposes of selecting the most reasonable and prudent plan or of complying with the Commission's obligations under the Michigan Environmental Protection Act. In fact, it is necessary that emissions be projected and considered in the decision criteria for selecting the proposed build plan.

Even if emissions are projected under each scenario and sensitivity, it is difficult to assess the significance of emissions and determine appropriate tradeoffs with other costs unless emissions are monetized. Fortunately, the Environmental Protection Agency has developed estimates of the social cost of carbon emissions, the social cost of methane emissions, and the social cost of nitrous oxide emissions that can be used in a reasonably straightforward way to monetize greenhouse gas emissions; these take the form of simple multipliers of emissions quantities that are globally applicable. The Environmental Protection Agency also has developed tools for the estimation of benefits from reducing emissions (marginal costs of emissions) that it uses in regulatory processes; these are more complex to apply because the marginal costs of emissions are partly locational. However, it is possible to establish a social cost per unit of emissions of criterion pollutants from each facility. I strongly urge that the Commission require a utility to use the Environmental Protection Agency's tools and apply a monetization multiplier to the emissions projected from each generating unit, and be required to report the net present value of total social cost of greenhouse gas emissions and the net present value of total social cost of criterion pollutants along with the net present value of required revenue for the optimal plan under each scenario and sensitivity.

The essence of environmental justice considerations is to examine the effects of emissions on the health and property of low-income and other disadvantaged communities. To do so will require mapping of the impacts of emissions overlaying the relevant demographics. The Staff are proposing to move this direction, but to truly honor the call to rectify historical environmental injustice, it is important to consider the impacts of existing generation and consider whether changes are warranted to enhance environmental justice. It also is important to characterize the magnitude of harms done to these communities. As a practical approach to this, I recommend that the harms to disadvantaged communities be estimated as a fixed proportion of the social cost of emissions (of each type) recommended above. This would provide a concrete estimate of harms of concern as a matter of environmental justice.

Finally with respect to this topic, I recommend that an understanding of tradeoffs between emissions harms and utility revenue requirements can best be achieved by contrasting the build plans, revenue requirements, and emissions costs under two modeling approaches:

1) Minimizing net present value revenue requirements subject to the usual considerations, and
2) Minimizing net present value of the sum of revenue requirements and social costs of emissions subject to the usual considerations.

This approach will reveal the differences in resource choices, revenue requirements, emissions, and emissions harms that result from considering and failing to consider the cost of harms attributable to emissions.

Generator Retirement Analysis

There are two aspects of the analysis of generator retirement that should be re-examined in the development of these guidelines and filing requirements.

First, when considering retirement of a generator earlier than is assumed in current depreciation rates, it is not correct that (as commonly assumed), the change in retirement date has no effect on required revenue because it is a sunk cost. There are four options for financing the net book value, three of which have an effect on required revenue and each of which should be evaluated in the IRP:

1. Conversion to a regulatory asset that will be depreciated and provide earnings on the undepreciated balance over the same period as the original depreciation schedule. This option does not change net present value of revenue requirements, but all other options reduce net present value of revenue requirements.
2. Accelerated depreciation based on the new retirement date.
3. Securitization of net book value at the time of retirement.
4. Immediate securitization of projected net book value at the new retirement date.

Because options 2, 3, and 4 reduce net present value of revenue requirements, consideration of these options can affect retirement decisions. Of course, the retirement analysis should also consider the effects of earlier financing of decommissioning costs and of avoided operations and maintenance costs.

Second, when considering retirement of a generator earlier than previously planned, the effects on emission should be considered. Monetization as described above should be included in the analysis.

Modeling Scenarios

The two modeling scenarios Staff proposes conceptually address the major question of a transition to cleaner electricity. I have two concerns about them as proposed, both of which can be addressed through specifications of the scenarios.

First, these scenarios do not provide much understanding of the significance of behind-the-meter resources. However, rather than adding a third scenario, I recommend a focus on the proper analysis of behind-the-meter resources in both scenarios. In particular, it should be required that:

1) A serious effort be applied to project under each scenario (and relevant sensitivities), the customer uptake of electric vehicles, building electrification, on-site solar, on-site fuel cells, on-site space and water heat storage, and on-site battery storage in light of the projected customer economics of those resources.
2) Load profiles be modeled based on various rate design options, including the effects of rate design on both customer uptake of the above resources and of customer-controlled operations (including bidirectional vehicle charging/discharging).
3) EWR uptake be modeled based on various rate design options, including the effect of those uptake decisions on load profiles.
4) In the context of the analyses above, treat utility rebates and other programs as resources that will change the uptake or operations of behind-the meter resources.

Second, these scenarios do not help with the question of the distribution of utility-owned or independently-owned grid-connected resources. In both scenarios, resources considered should include distribution-grid connected solar and storage resources as well as transmission-connected resources. Analysis of distribution-connected resources should account for differences in grid losses of both energy and capacity, and for avoided substation costs including both changes in expected life of equipment due to reduced wear and changes in expected upgrade dates due to capacity addition deferrals.

In both of the above analyses, there is a difference between the projected effects of one-off resources and of ubiquitous resources of these types. This is particularly true for behind-the-meter resources where rare resources will provide little grid benefit or cost but ubiquitous resources will create both grid benefits and costs that should be accounted for. Analysis requirements should address this.

Risk Assessment

The Staff proposal regarding risk assessment largely leaves the approach to the discretion of the utility. We have enough experience both here and elsewhere in the industry to improve the risk analysis. Filing requirements should specify aspects of the risk analysis.

First, there is a statutory requirement to assess fuel-price risks. This risk should be called-out for separate analysis and included in all analyses. Current use of fuel-price scenarios fails to capture risks associated with “normal” variation in fuel prices. Further, the variation in fuel costs is also associated with load variation related to weather and economic conditions and with weather-related variation in production from resource-limited resources like hydropower, wind, and solar. In the spirit of normal financial analysis, I recommend that this risk analysis should be done using standard mean-variance analysis to find an efficient resource mix (a la Shimon Awerbuch’s portfolio analysis). In the alternative or additionally, stochastic discounted cash flow analysis can use discount rates that include an uncertainty premium (lower discount rate for costs).

Second, due to considerations of climate change any new fossil-fueled assets may need to be retired sooner than they would wear out due to age or use. Similarly, future technology costs may make assets obsolete before they wear out because the cost of operating and maintaining assets exceeds the cost of replacing them; this is essentially what is happening now with coal and nuclear plants. Risk analysis should be performed specifically with respect to asset life and the depreciation rates used in evaluating the revenue requirements should be adjusted accordingly. Essentially, an investment that is risky due to potential regulatory or technological obsolescence should be depreciated rapidly while one that is low-risk should be depreciated based on wear-out.

Third, risk analysis should address resource adequacy as a weather-related phenomenon. It is necessary to develop a resource plan that complies with the currently applicable resource adequacy standards. However, as climate and the power system evolve, risks will be increasingly weather-based rather than being related to peak load and generation reliability. Furthermore, there is current evidence that thermal generation outages are weather-related. Risk analysis should begin to examine resource adequacy with respect to specific weather scenarios and the likelihood of those weather scenarios. This approach can lead to problem-solving in resource plans, such as how to handle a polar vortex or a heat wave, rather than just considering an abstract reserve margin.

Michigan Energy Innovation Business Council
115 W. Allegan, Suite 710
Lansing, MI 48933

Advanced Energy Economy
1010 Vermont Ave NW, Suite 1050
Washington, DC 20005

Dear Ms. Gibbs,

Advanced Energy Economy (AEE) and the Michigan Energy Innovation Business Council (Michigan EIBC) appreciate the opportunity to provide comments in response to Staff's updated draft integrated resource plan (IRP) filing requirements and planning parameters. We have been active participants in many MI Power Grid workshops since the initiative's launch and appreciate Staff's time, effort, and willingness to receive robust stakeholder feedback throughout these proceedings. We look forward to further engaging with the Commission and Staff as Phase III of the Michigan Integrated Resource Planning Process (MIRPP) continues this spring.

Our comments below are generally supportive of the updates Staff has made to the MIRPP and the filing requirements. We have provided recommendations for how the Commission can more accurately value long- and short- duration energy storage in the future, feedback on the sensitivities in the two proposed modeling scenarios, and general responses to the draft filing requirements. Our comments are intended to assist Staff as it develops clear guidelines for utilities to follow. We hope that you find them helpful as Staff finalizes both documents.

If you have any further questions about these comments, please contact Ryan Katofsky and Laura Sherman.

Sincerely,

Laura Sherman
President
Michigan EIBC
Lansing, MI
laura@mieibc.org

Ryan Katofsky
Managing Director
Advanced Energy Economy
rkatofsky@aee.net

1. *Please provide any feedback supporting or suggesting changes to Staff's proposed MIRPP.*

VI. Modeling Scenarios, Sensitivities and Assumptions

Scenario #1: Base Case

AEE and Michigan EIBC generally support the changes proposed to Scenario #1. We believe that Staff's decision to require utilities to incorporate non-legislatively mandated state and utility emissions reduction goals at 85% of their respective announcements is a more accurate representation of the State's and MISO's energy future than the existing planning parameters that do not require any carbon reductions to be modeled. We believe that doing so also better positions the Commission and utilities to adjust to future legislatively mandated reductions either at the state or federal level.

We are also supportive of Staff's decision to require utilities to incorporate long- and short-duration storage resources in this scenario. However, we have questions on how Staff intends to direct utilities to incorporate storage in their modeling. Moreover, as the Commission refines how utilities are to connect their distribution system plans and the IRP process, developing an appropriate way to consider storage will become increasingly important. Storage is a unique grid asset that can provide power as both a distributed energy resource (DER) and utility-scale asset, over different timescales, and provide a range of services. As a result, we seek clarity on how Staff intends to direct utilities to consider these different applications. In addition, we ask that Staff clarify how it intends to define available best practice methodologies for storage modeling. Below we offer some recommendations in this regard that are applicable to all scenarios and sensitivities and raise concerns that the current IRP modeling process does not (and currently cannot) adequately value storage.

For the last year, the Institute for Energy Innovation (IEI), in partnership with Michigan EIBC, 5 Lakes Energy, and Dr. Annick Anctil, has been developing an energy storage roadmap for Michigan as requested by the Department of Environment, Great Lakes, and Energy ("EGLE"). As part of this project, the team modeled the optimal use of both behind-the-meter commercial storage systems and front-of-the-meter storage systems. The bulk grid modeling was completed using an open-access model developed by 5 Lakes Energy (called STEP8760). STEP8760 contains two major logical components. The annual production planning module calculates the optimal operation and associated costs to serve projected load given a fixed set of generation and demand reduction resources. The capacity additions module calculates the optimal addition of resources to meet demand given the way that existing and new resources would operate as described in the production planning module. In both modules, optimality is determined as the least-cost plan that satisfies all applicable constraints.

The value of storage resources emerges in modeling analysis when time variation in power is fully represented (e.g., when storage charges from low-cost plants and discharges to displace high-cost plants.) As a result, IRP models that represent reasonably frequent charge-discharge cycles or high variation in real time energy cost appropriately value energy storage. If a model lacks these capabilities, it is unlikely to select high-value storage resources.

During initial testing of STEP8760, it was apparent that existing storage in Michigan at the Ludington Pumped Storage Plant was predicted by STEP8760 to operate less than it actually economically operates. This is because STEP8760 simulated less variation in the marginal cost of power than occurs in the actual wholesale market operated by MISO. Although a number of features added to STEP8760 to increase the realism of its price variations were beneficial, the model nonetheless fell short of simulating the degree of price variation in the MISO market.

Subsequent to the finding that STEP8760 does not provide sufficient price variation to match real-world conditions, several other researchers released similar findings. For example, Lawrence Berkeley National Laboratory released a paper showing that the Cambium model that they developed and use along with the National Renewable Energy Lab has this same deficiency.[1] The researchers found that simplifying planning assumptions such as hourly planning resolution and the substitution of reserve margins for ancillary services "cause the flexibility and scalability benefits of energy storage to be undervalued."

It is clear that in current IRP models with hourly resolution, the value of storage is systematically undervalued, and IRPs based on these models select less storage than is actually optimal. There exist several solutions that the Commission could adopt to address these concerns as part of the IRP filing requirements. First, utilities should be required to meaningfully evaluate the full value

[1] Seel, J. and Mills, A. November 2021. "Integrating Cambium Marginal Costs into Electric-Sector Decisions." *Lawrence Berkeley National Laboratory.* Available at: https://eta-publications.lbl.gov/sites/default/files/berkeley_lab_2021.11-_integrating_cambium_prices_into_electric-sector_decisions.pdf.

of energy storage as a potential resource, both on the supply side and the demand side. In the near term, the Commission could require the utilities to solicit competitive proposals (in alignment with the Competitive Procurement Guidelines) from storage providers wherein the storage provider would operate the energy storage system, receive any revenue from that operation, and sell capacity credits to the utility. Alternatively, the Commission could require utilities to model storage outside of the current IRP models, considering the accurate operation of the storage resources and value generated, and bring the results of that separate modeling work as inputs to the IRP models. In the long term, as IRP models evolve to better represent the value of energy storage and other emerging resources, utilities should be prepared to incorporate novel modeling techniques in each subsequent IRP.

As part of any of these recommendations, there are some best practices to consider.[2] Models should use tools that represent a full year of grid operations. This is necessary to accurately capture the effects of high renewable penetration on future resource needs, reliability, and the full value of long duration energy storage resources. Models should also use sub-hourly data or evaluate energy storage on a net cost basis. IRPs should also consider the full array of energy storage technologies, including mature and emerging technologies, to reflect the diverse array of services that energy storage resources can provide, from dynamic grid balancing to firming capacity during multi-day events. Other best practices include accounting for the full range of services, co-benefits, value streams, and operational benefits of energy storage. It is also necessary to use current cost information, ideally discovered through RFPs.

Staff also recommend that utilities incorporate technology costs for solar, storage, and other emerging technologies that decline with commercial experience. We ask that Staff provide further guidance on how utilities should model these cost declines. We believe it is necessary that utilities incorporate cost projections that are accurate based on market projections to develop a resource blend that is cost-effective and meets projected load growth. We recognize that this is more challenging to perform when technology costs and performance are changing rapidly, and markets may be growing in a non-linear fashion. Therefore, engaging the companies that are providing

[2] See for example, recommendations from Pacific Northwest National Laboratory (https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-28627.pdf) and the Energy Storage Association (https://energystorage.org/wp/wp-content/uploads/2019/09/esa_irp_primer_2018_final.pdf).

these technologies is critical to developing an accurate understanding that can inform both the IRP and distribution system planning activities.

Scenario #1: Sensitivities

In describing the base case on p.18, Staff states that "state and utility goals and announcements that are not legislated are applied at 85% of their respective announcements to hedge the uncertainty of meeting these goals and announcements at their proposed respective timelines." Given that this 85% hedge represents a baseline assumption for the scenario, AEE and Michigan EIBC strongly recommend that Staff remove sensitivity number 4 that requires utilities to perform a model run that only considers legislatively mandated carbon goals. This sensitivity is counterintuitive to the baseline assumption provided at the beginning of the section. We also believe this sensitivity is unnecessary because of the baseline assumption of applying 85% of non-legislated goals already accounts for the uncertainty associated with these goals.

AEE and Michigan EIBC also recommend that Staff incorporate a sensitivity that reflects weather in an atypical year. Without this sensitivity, the IRP is unlikely to identify a portfolio that remains least cost under the range of weather conditions that are likely to occur.

Scenario #2

AEE and Michigan EIBC are supportive of the requirements described in Scenario 2. Specifically, we support the inclusion of EV adoption and customer electrification adjustments that are more consistent with the most recent MISO Future 3.[3] We believe it is critical for utilities to consider this high electrification scenario to accurately develop planning processes that can account for higher EV adoption and consumer electrification, and to also be able to consider the increased availability of flexible demand and supply when developing resource portfolios.

[3] MISO Futures Report. Available at: https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf. p. 70.

Scenario #2: Sensitivities

Staff raises the question of adding carbon price sensitivity as one of the Scenario #2 sensitivities. AEE and Michigan EIBC encourage Staff to require IRP parameters to include a low or no carbon price, as well as medium and high carbon price sensitivities to accurately consider the potential for a legislatively mandated carbon price, either at the state or federal level, over the timeline of the IRP planning horizon. We recommend that Staff incorporate a phase-in of these carbon price scenarios over a 10-year period to simulate how a mandated carbon price could be introduced.

2. *Please provide any feedback supporting or suggesting changes to Staff's proposed Filing Requirements.*

AEE and Michigan EIBC believe that the proposed changes to the Filing Requirements generally appear consistent with the changes in the proposed MIRPP. While not exhaustive, we offer comments and recommendations below on the proposed Filing Requirements:

- "Approval of Costs"
    - In Subsection (I) we support the addition of item (n), which refers to the procurement strategy, using the most recent Commission-approved Competitive Procurement Guidelines. We similarly support the same inclusion and reference to these guidelines in Subsection (II) item (k). More generally, we reiterate prior comments by AEE and Michigan EIBC, made during the development of the updated competitive procurement guidelines, that the Commission should seek to maximize participation of independent power producers, which can drive competition and reduce costs and risks for utility customers.
    - We support the addition of Subsection IV (page 11) and the Commission's effort to separate out demand response and distributed generation programs from energy waste reduction. This differentiation will likely allow the Commission to gain greater insight into each individual program, as opposed to an aggregated portfolio.
    - In Subsection (III), item (c) and in the new subsection (IV), item (c) "Maximum single event demand reduction," we ask that the Commission clarify if this is potential or actual demand reduction.

- "IRP Filing, Data, and Documentation" (formerly titled "Report and Documentation")
    - We support the addition in Subsection (V), items (b-iii) and (d) regarding risk assessment. We note that risk assessment should include risks associated with extreme weather, as well as portfolio risks related to potential future clean energy and greenhouse gas targets. We also suggest that the Commission make explicit recommendations detailing the most effective tools and models for conducting risk assessment. Specifically, we recommend that the Commission consider the efficient portfolio approach as described in detail in Simon Awerbuch's 2006 paper titled "Portfolio-Based Electricity Generation Planning: Policy Implications for Renewables and Energy Security."[4] Awerbuch suggests that energy planners abandon their reliance on traditional "least-cost" stand-alone measures and choose to evaluate renewable energy sources relative to their risk contribution to a mix of generating assets. Evaluating alternative resource portfolios, as opposed to the resources themselves, will allow for the selection of more cost-effective investments over time.
    - We support the addition of Subsection (VIII) item (a-ii) to document historic performance of DSM programs. Doing so can help stakeholders understand where improvements may be warranted that can improve the contribution of demand-side resources to meeting IRP requirements.
    - Consideration of energy storage is now included in several sections of the IRP Filing Requirements, which have previously lacked any specific mention of energy storage. We encourage the Commission to maintain, in the proposed outline provided in the filing requirements, the requirements to consider and model energy storage as in Subsection X item (viii), Subsection XII, Subsection XIV, and Subsection XVI. AEE and Michigan EIBC also appreciate the explicit addition of energy storage to the IRP Planning Parameters and scenarios.
    - We strongly support the additions to Subsection (X) regarding DERs, the alignment of the IRP with distribution planning, as well as EV and beneficial electrification (items (vii) through (x)). We also note here that these topic areas are particularly ripe for early engagement with stakeholders, as the utilities develop their

[4] Available at: https://link.springer.com/article/10.1007/s11027-006-4754-4#auth-Shimon-Awerbuch.

assumptions and approaches to forecasting. For example, for a given level of deployment of EVs and beneficial electrification, there can be a range of outcomes with respect to assumed overall peak demand impacts, which in turn has important implications for new capacity needs. In addition, as geothermal (ground source) and air-source heat pumps increase in use in Michigan, it is important to consider the use of these resources for beneficial electrification and load shifting. We highly recommend the Commission consider adding additional language that explicitly considers geothermal and air-source heat pumps as part of beneficial electrification.

- In Subsection (XVI) we support inclusion of items (f) and (g) related to best practices for maintaining a strong Michigan workforce and supply chains.
- Environmental Justice considerations in the IRP Filing Requirements (Subsection XVIII): AEE and Michigan EIBC support the Commission's effort to recognize emission reduction and environmental justice targets as set out by Governor Whitmer's Executive Directive 2020-10 and President Biden's economy-wide emissions reductions targets, as cited in the footnotes on page 33. In particular, the inclusion of new and improved environmental justice considerations is a major step forward in identifying how Michigan's energy system impacts historically marginalized communities (Subsection XVIII, items (f) through (l)). It is critical that the Commission continue to reference and require utilities to use the Michigan Environmental Justice Screening Tool to identify how changes in their proposed resource plan impact vulnerable communities. In addition to its inclusion in Subsection XVIII item (h), we recommend that item(g) also include the following statement: "The Michigan Environmental Justice Screening Tool or equivalent should be used for the identification of vulnerable areas." To understand the environmental justice impacts of expected changes in criteria pollutants, models and projections must disaggregate these pollutants across specific communities in which the pollutants are being emitted rather than aggregating these changes across the entire utility territory. Although some of these pollutants are global or regional in their dispersion patterns, particulates and certain heavy metals (including mercury), are deposited locally and it is therefore critical to evaluate the benefits and harms of these pollutants on a community-by-community basis.

3. *Are stakeholders generally supportive of two MIRPP scenarios for all rate regulated utilities?*

AEE and Michigan EIBC are supportive of the two MIRPP scenarios for all rate regulated utilities. While we have provided comments above to adjust and consider additions to both scenarios, we believe that the two scenarios can accurately portray a planning future for utilities that incorporates new technologies, cost-effective investments, and improves reliability and resilience. Using two MIRPP scenarios will also assist in alleviating work for Commission Staff, utilities, and participating stakeholders as the Commission initiates IRP proceedings in the future.

4. *Do Stakeholders feel that the Electrification and Decarbonization scenario would adequately take the place of the two additional runs directed by the Commission in the February order in U-20633?*

Yes. We believe that the Electrification and Decarbonization scenario puts utilities in a position to prepare for a high electrification and decarbonization scenario should it occur in the future. We appreciate Staff's efforts to simplify this process while maintaining a thorough and comprehensive set of IRP Planning Parameters.

CITY OF ANN ARBOR, MICHIGAN
301 E. Huron, P.O. Box 8647, Ann Arbor, Michigan 48107
Phone (734) 794-6110 FAX (734) 994-8296

January 7, 2022

Naomi Simpson
Michigan Department of Licensing and Regulatory Affairs
State of Michigan
Landing, MI

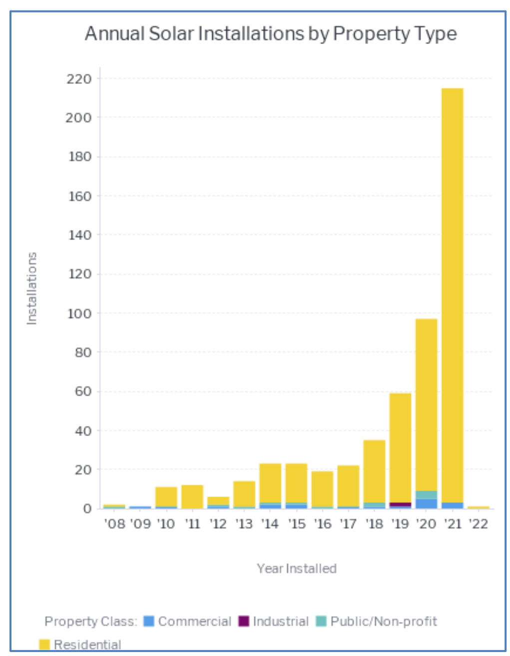
RE: Feedback for Draft Michigan Integrated Resource Planning Parameters

Dear Ms. Simpson

We are writing to provide feedback regarding the Integrated Resource Plan (MIRPP & Filing Requirement). The City of Ann Arbor believes a well-designed IRP filing and modeling requirement is essential to develop short-term and long-term resource planning to optimize ratepayers' benefits. The MPSC has outlined two scenarios and multiple sensitivity analyses for all Michigan rate-regulated utilities. We recommend MPSC also consider the following sensitivities for IRP modeling within the IRP framework for reasons described further in this letter.

The DRAFT Michigan Integrated Resource Planning Parameters shared at the December 16th Stakeholder Meeting outlined two scenarios. For scenario #1 Base Case, the Load projections include three sensitivities. The draft report states for the option high load growth as "…Increase the energy and demand growth rate by at least a factor of two above the base case energy and demand growth rates..." It is unclear, however, if this sensitivity includes:

- The likelihood of significant load increases due to having more large industrial customers choosing to relocate to Michigan; or
- Increasing electricity demand because of the shift toward electrification of product lines and automation?



If these two factors were not included in the assumptions for Scenario 1, we strongly encourage they be factored in. In addition, we recommend adding the projection of load increase due to the MPSC approved DTE Electric and Consumers Energy's special rates to help attract and retain advanced manufacturing rate offering to the high load growth sensitivity analysis. Adding the load increase due to the special rate into the High load growth sensitivity will provide an evaluation of the long-term impact of special rates for high-volume industrial customers on capacity expansion planning, load shape change, rate base, and rate growth for existing ratepayers.

Secondly, we recommend adding the High Distributed Renewable Generation Growth Sensitivity analysis to Scenario 1. The massive growth of distributed renewable energy generation since 2000 will likely continue in the next decade because of rapidly declining solar costs, rising utility rates, growing calls for resilience and energy independence, and increasing awareness of the need for a massive shift to clean energy to address the climate crisis. The chart on the right shows the surge of residential rooftop solar installation just in Ann Arbor over the last decade. This adoption curve is illustrative of the latent potential for DG to transform our electric grid across Michigan. For the IRP Scenarios, we would love to see modeling, if not already included, that shows the impact of massive DG adoption (assuming the 1% cap is lifted) on electric reliability. Specifically, we'd like to understand if the grid handle the intermittency of renewable energy? And what role does storage play to help address this intermittency? Additionally, does this modeling provide insights into where grid upgrades are needed and how best to phase investments in system improvements to ensure efficiency and cost effectiveness? The IRP analysis would be an excellent opportunity to evaluate the long-term impact of rapid growth of rooftop solar deployment on generation fleet capacity expansion, distribution, transmission capacity, etc. The result would be helpful for policymakers and utilities to develop strategies and policies to guide the growth of the renewable energy industry in Michigan.

For Scenario 2. Electrification and Decarbonization Future Sensitivities, we recommend two additional sensitivity analyses as follows:

- Carbon price sensitivity: This would evaluate the additional costs that would incur to ratepayers because of imposing a carbon price. We recognize there is regulatory uncertainty around carbon price legislation but it's impact would be significant if passed. Given that it takes years to plan and build new generation capacity and that ratepayers are currently committed to paying for existing generation, we feel it would strongly behoove the Commission, rate payers, and the utilities to assess the impact a carbon price could have on utility rates, generation, and operations. A 2021 study released by Purdue University shows the long-term impact on resource planning under various scenarios requested by the Indiana Utility Regulatory Commission.[1] Based on the analysis, a price on CO2 emissions was added to multiple scenarios. The CO2 price started at $2.5/ton in 2025 and grows by $2.5 per ton per year thereafter. The renewable generation capacity (wind and solar) doubled or tripled by 2030 because of the CO2 price. A similar analysis should be conducted in Michigan with a focus on what would be the additional NPV of the high renewable capacity compared to the base case or preferred plan? Such a study should also address any impacts to rates. This simulation model could provide the optimal resource plan under various uncertainties and the associated mitigation costs.

- Growth of Voluntary Green Pricing Programs and Renewable Power Purchase: More residents and businesses are becoming environmentally conscious and willing to pay extra for renewable energy to offset their carbon footprints. They also want to make sure the additional costs they had paid for renewable energy are invested in building more renewable energy capacity and accelerating the retirement of fossil-fuel generation facilities. However, we don't have a program that assures customers that their contribution results in early retirement or the building of fewer fossil-fuel generation facilities. In 2020, the City of Ann Arbor intervened in DTE Energy's VGP filing (U-20713 and U-20851). We expressed multiple concerns on the VGP filing, as discussed in our testimony. The first concern is the VGP program offerings are undersized and couldn't even meet the City of Ann Arbor's decarbonization goals, let alone other publicly stated goals in their service territory. Secondly, the City proposed that DTE Energy offer a virtual power reduction program to encourage deep energy waste reduction projects. Thirdly, the City recommended offering aggregation in the VGP program to accelerate the retirement of fossil-fuel generation facilities, especially coal units. An option that guaranteed a reduction in current fossil generation would be a unique offering and boost subscription of the VGP programs. However, it takes comprehensive optimization modeling to estimate the impact of the VGP programs and aggregated renewable energy purchases on resource planning. We urge MPSC to call for a sensitivity analysis on residents and businesses' growing renewable energy demand. The City of Ann Arbor has started renewable energy aggregation discussions with large local business entities and has seen notable interest – interest we know exists in other communities and in the private sector. A sensitivity analysis could help customers know the needed renewable energy capacity to retire a coal unit and when. We are confident the findings will significantly boost the participation of VGP programs and the decarbonization of our electric grid.

As you may know, the City of Ann Arbor and Washtenaw County have set ambitious goals related to clean energy and carbon neutrality. To achieve a just transition to community-wide carbon neutrality by the year 2030, we must take action now. That is why the City has implemented, has initiated, or is planning major activities related to installing local distributed generation, transitioning our public and private vehicles to electric, making massive improvements in energy efficiency, and pursuing a massive beneficial electrification program, starting

[1] Douglas J. Gothan, Scenario Analyses for IURC Report to the 21st Century Energy Policy Task Force, Purdue University, State Utility Forecasting Group, Oct 2021; https://www.purdue.edu/discoverypark/sufg/docs/publications/IPU%20Gotham%202021.pdf

in the residential sector. As we undertake this work, we are discovering numerous barriers – many of which are relevant to resource planning. To explore the options to implement the carbon neutrality goal by 2030, the IRP modeling could be a powerful and irreplaceable tool to guide and synergize policymakers, utilities, and local governments efforts to address climate change, together.

Thank you in advance for receiving our thoughts. We look forward to being involved in this work going forward and ensuring Michigan IS the leader in the clean energy economy.

Sincerely,

Missy Stults
Director, City of Ann Arbor Office of Sustainability & Innovation
301 E. Huron Street, Fifth Floor
Ann Arbor, MI 48104
mstults@a2gov.org

Fang Wu, MBA
Energy Manager
301 E. Huron Street, Fifth Floor
Ann Arbor, MI 48104
fwu@a2gov.org

MICHIGAN BIOMASS

P.O. Box 11 • Ithaca, Michigan 48847
989.763.0672 • michiganbiomass.com

January 5, 2022

Comment from Michigan Biomass: Case No. U-20633
Draft IRP Filing Requirements and Draft IRP Parameters

Michigan Biomass is a business coalition of the state's wood-fire power plants[1] that supply Consumers Energy Co. with energy and capacity under PURPA power purchase agreements in place prior to 2008. Following are our comments on the Draft IRP Filing Requirements and Draft IRP Parameters of the MPSC's Phase III IRP under MI Power Grid (Case No. U-20633).

Our comments are focused on finding ways to help ensure that regulatory frameworks and rulemaking processes regarding electric utility resource planning processes adequately consider the full scope and co-benefits of biomass power generated from sustainably sourced wood residuals, mill byproducts, and non-fossil alternative fuels such as tire-derived fuel (TDF). See Attachment A, Values of Biomass Power Generation.

Our concern is focused on the lack of specifics that compel the filing utility consider <u>*all available*</u> generation resources in their proposed action plan, and what appear to be inconsistencies and lack of clarity within statutory language as to when consideration of existing resources <u>*is*</u> required (i.e., filings doc, pg. 27, XIV) Resource Screen) and when it <u>*isn't*</u> required (i.e., filings doc, pg. 2, Pre-Filing Request for Proposals).

While we understand much of these documents is based in statutory language that cannot be revised without legislative action, some of our comments are offered in the form of edits to that language to convey our arguments.

RFPs, analyses, and resource plans with the MIRPP must include resources operating under existing PPAs for energy and capacity.

> Michigan statute establishing MIRPP clearly states that "all reasonable" energy and capacity options must be considered in the filing utility:
>
> MCL 460.6t(5) An integrated resource plan <u>shall include all of the following</u>:
>
> (k) An analysis of the cost, capacity factor, and <u>*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.*</u>

It is our experience, and there is clear evidence in the company's current IRP (U-21090), that our customer, Consumers Energy, has not considered "all reasonable options" and there is nothing in the draft filing requirements that would change this practice, vis-a-vis the narrow scope of the company's request for proposal for natural gas-only generation, which excluded the biomass plants from participating in this IRP:

[1] Cadillac Renewable Energy, Genesee Power Station, Grayling Generating Station, Hillman Power Co., National Energy of Lincoln, and National Energy of McBain – collectively known as the biomass merchant plants or BMPs.

> The RFP issued on January 6, 2021, was tailored to *existing gas resources in Zone 7*, or easily transferrable to Zone 7, to solve the need for safe, reliable, affordable, and clean resources with minimal operational execution risks.[2]

As a carbon-neutral, baseload generation resource, biomass power is a "safe, reliable, affordable and clean resource" that was purposely omitted from the required RFP in U-21090, and we see nothing in the MIRPP filing requirements that would compel a utility to give existing portfolio renewables the same consideration as future resources, which could lead to an erosion of the state's baseline renewables. In this reference case, the utility assumes a generating facility is "retired" at the end of its PPA, when in fact, these facilities have decades of useful life beyond those PPAs.

Additionally, the biomass plants' participation in this process is further limited in the RFP process because at 20 to 36 MW each, they fail to meet the 200 MW or larger size requirement in MCL 460.6t(6) to offer a non-solicited proposal in lieu of participating in the RFP.

Not being included in the RFP and not being included as a potential viable renewable energy resource in proposed plan effectively shuts these biomass plants out of the process and denies Michigan's electricity customers from benefiting from this generation resource.

Frameworks of the MIRPP should not permit filing utilities to pick and choose reliable, available resources, but consider all resources that are available.

While we understand such amendments would require legislative action, we believe MCL 460.6t(5)(k) provides the Commission the authority to build this requirement into the MIRPP.

DRAFT Integrated Resource Plan Filing Requirements

Pre-Filing Request for Proposals

Edits pages 2-3

> Each electric utility whose rates are regulated by the Commission shall issue a request for proposals (RFP) to provide any new **OR OTHERWISE AVAILABLE** 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 **AND MCL 460.6T(5)(K)**
>
> The utility shall comply with the following:
>
>> d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, pursuant to MCL 460.6t(6) **AND MCL 460.6T(5)(K)**; and
>>
>> e) The RFP shall allow for proposals to provide new **OR OTHERWISE AVAILABLE** supply-side capacity in the form of a purchase power agreement for a period that **COMPLIES WITH MCL 460.6t(5)(K).** ~~is the lesser of the study period or of the useful life of the resource type proposed~~.

[2] Direct testimony, Richard Blumenstock, CECo. IRP application U-21090, pg. 49

Risk Assessment Methodology

By extension, the omission of biomass power from a proposed resource plan as described above would preclude these resources from consideration in a filing utility's risk assessment as noted on page 5:

> The 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 to determine how each strategy would perform in an unexpected range of possible futures.

As stated previously, the fuel and generation diversity that the biomass plants bring to Michigan's energy portfolio are significant, including reducing risk, which was clearly demonstrated during the 2019 polar vortex when they were able to generate more MWh and optimize performance and reliability while nature gas could not because fuel was diverted to heating uses due to pipeline constraints.[3]

The biomass power plants also shelter utility ratepayers from economic risk by assuming all the financial risks as an independent, third-party generation resource, and therefore, warrants inclusion in these risk assessments.

Renewable Resources

Similarly, the value of the biomass plants' co-benefits and renewable attributes would be lost if not included as a renewable resource in the filing utility's proposed resource plan as noted in II) Renewable Resources, d) Ancillary service costs and e) Cost of purchased renewable energy credits (page 8).

Biomass power is a significant source of renewable energy. In 2019 Michigan's biomass plants were second only to wind in the number of RECs used to comply with the RPS; a position it has held consistently over the 12 years the program has existed.

Our track record here is proven. The biomass plants helped lower RPS implementation costs for Consumers Energy by satisfying no less than 40% of the company's RPS requirement for the first six years of the RPS with renewable power we were already providing under contract at non-renewable rates. That no-cost contribution to the company's RPS requirements resulted in ratepayer savings as it helped accelerate ending the $3 surcharge that ratepayers paid to fund the initial development of renewable energy systems.

Renewables and Renewable Portfolio Standards Goals

It goes to reason that if the biomass plants are excluded from RFP participation, prohibited from submitting unilateral proposals because of their size, and are not included in a proposed utility resource plan that they would not be part of a utility's plans to meet its RPS goals.

Michigan Biomass understands that the IRP is a forward-looking process, however, the potential that the process results in a resource plan that would allow or facilitate the erosion of baseline renewable energy resources already in a filing utility's portfolio is real, representing a net loss in renewable energy and capacity, like that which the biomass plants provide.

The MIRPP needs to ensure filing utilities adequately consider the RPS impacts, decarbonization impacts and continued contributions that its existing renewable energy resources provide.

---

[3] Michigan Biomass comment U-20464

IX) Renewables and Renewable Portfolio Standards Goals:

Proposed edit page 21

Projected energy purchased or produced by the utility from renewable energy resources.

d) A description of how the electric provider's plan is consistent with the renewable energy goals required by the Michigan Legislature (e.g., 35% combined renewable energy and energy waste reduction goal by 2025) **INCLUDING AN EXPLANATION OF ANY LOSS OF RENEWABLE ENERGY OR ENERGY WASTE REDUCTION RESOURCE IN ITS PORTFOLIO ANYTIME DURING THE PLANNING PERIOD**;

Proposed edit page 22

The following non-exhaustive list suggests several elements that may be included:

b) Detailed resource plan:

VI. DESCRIBE ANY LOSS OF RENEWABLE ENERGY OR ENERGY WASTE REDUCTION RESOURCE WITHIN THE UTILITY PORTFOLIO ANYTIME DURING THE PLANNING PERIOD

DRAFT Michigan Integrated Resource Planning Parameters

Michigan Biomass generally agrees with the content and direction of the planning parameters documents, particularly Sec. VIII. Additional IRP Requirements and Assumptions, item 4 that stipulates the IRP analysis must consider environmental benefits and risks.

Our concern here, similar to previous comments, is that the environmental benefits of power generation from sustainable organic feedstock like forest residual and mill byproducts, may be overlooked, given the demonstrated tendency for utilities to disregard facilities already a part of their portfolio, and having shown a propensity to consider the maturation of a PPA as a facility "retirement" when, in fact, the facility likely has decades of useful life and environmental contributions to make.

We support the intent of item 7 under Sec. VIII for capacity factors based on demonstrated performance and geographic location. It has been our experience, in previous cases before the MPSC, that flimsy data on unproven technologies can sometimes be used for decision-making (hybrid gas proxy U-18090) that disadvantaged diverse energy resources like biomass power.

The need to look at energy diversity was made clear through the Statewide Energy Assessment outline from February 2019 following the polar vortex, and the Commission needs to continue to look at this important aspect of advanced planning, as written in *Michigan Statewide Energy Assessment Outline* from Case No. U-20464 (page 2).

IV. System Risks, Interdependencies and Vulnerabilities

A. Michigan's unique strengths - gas storage; access to electricity and gas markets; gas transmission capacity; Ludington pump station; *diversity in power supplies*; propane storage capacity and proximity to Sarnia; Ontario fractionator/refinery; electric demand response capabilities.

B. Changing landscape of risks

2. Fuel procurement

a. Generation diversity and interdependencies

b. Fuel supply sourcing and supply chain

Sincerely,

Gary Melow, Director

Attachment A

Values of Biomass Power Generation

- Baseload generation
  - Dispatchable
  - Load-following
  - Line loss mitigation
  - Resource/fuel diversification
    - Geopolitically secure
      - Local transport
      - On-site fuels storage
    - Non-commodity/stable pricing
  - Weather resilient
  - Baseload renewable
    - 13% Michigan's 2019 RPS compliance RECs[4]
    - Backs up intermittent renewables
  - Zonal resource
- Cost-effective, efficient forest management tool
  - Aids forest health and carbon sequestration
- Climate
  - Offsets short-term fossil emissions
  - Offsets long-term methane emissions from decomposition

[4] *Report on the Implementation and Cost-Effectiveness of the P.A. 295 Renewable Energy Standard* MPSC, February 16, 2021.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	))))	Case No. U-20633

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

The Michigan Public Service Commission ("Commission") issued an Order on September 24, 2021 directing Commission Staff to begin Advanced Planning Phase III of the Integration of Resource, Distribution, and Transmission Planning workgroup. Specifically, this phase is to revisit the Michigan Integrated Resource Planning Parameters ("MIRPP"), integrated resource plan ("IRP") filing requirements, and Demand Response ("DR") and Energy Efficiency Studies which are required to be evaluated every five years under MCL 460.6t(1).

The Commission directed Staff to create a redline version of the MIRPP published on November 21, 2017, that reflects the recommendations developed through the Integration of Resource, Distribution, and Transmission Planning workgroup to date, as well as feedback from stakeholders and the directives for building a carbon-neutral Michigan pursuant to Executive Directive 2020-10. Pursuant to this direction Staff conducted a workgroup on December 16, 2021, presented draft IRP filings requirements and parameters, and solicited feedback thereon. Pursuant to that solicitation the Association of Businesses Advocating Tariff Equity ("ABATE") provides the following comments below.

II. COMMENTS

While ABATE is generally supportive of Staff's filing requirement and planning parameter proposals, the filing requirements should further clarify that IRPs must demonstrate any proposed resource plan or alternative plan meets minimum reliability guidelines. Specifically, the following should be added to either Section XV (Modeling Results) or Section XI (Capacity and Reliability Requirements):

> **The utility must provide a detailed demonstration that its Proposed Resource Plan and any alternative resource plans will meet all applicable resource adequacy requirements. This analysis should definitively demonstrate that the resource plans will meet or exceed the 1-in-10 loss of load probability standard under resource dispatch assumptions vastly similar to actual operations within the utility's RTO, rather than assuming the utility's balancing area is an island with access to outside resources via transmission. For utilities operating in the MISO RTO, a separate analysis should be conducted that considers and incorporates a seasonal resource adequacy construct.**

Such a requirement will address reliability and resilience issues raised by prior utility IRPs and noted by various parties. (See e.g. Case No. U-20963, 7 Tr 2280, 2564, 2632-33, 8 Tr 3469, 3481-91.)

III. CONCLUSION

Pursuant to Staff's solicitation of feedback and for the reasons set forth herein, ABATE recommends Staff consider and incorporate the comments raised above.

Respectfully submitted,

CLARK HILL PLC

By: _/s/ Stephen A. Campbell_
Stephen A. Campbell (P76684)
Attorneys for Association of Businesses Advocating Tariff Equity
212 East César E. Chávez Avenue
Lansing, Michigan 48903
517-318-3100
scampbell@clarkhill.com

Date: January 5, 2021

ClarkHill\07411\414800\265267583.v1-12/29/21

From: mgkushler@aol.com <mgkushler@aol.com>
Sent: Tuesday, January 4, 2022 4:25 PM
To: Gibbs, Kayla (LARA) <GibbsK2@michigan.gov>
Cc: Simpson, Naomi (LARA) <SimpsonN3@michigan.gov>; Hudson, Patrick (LARA) <hudsonp1@michigan.gov>; Gould, Karen (LARA) <GouldK1@michigan.gov>
Subject: ACEEE Feedback on IRP & MIRPP Filing Requirements

Hello Kayla (& other MPSC Staff),

I hope that it is ok to just send my couple recommendations via this format.

I was unfortunately unable to attend the December 16th MIRPP meeting, due to illness. My comments below are based on my review of the slide set presented and posted for that meeting. Please let me know if my interpretations below are incorrect.

Based on my review of the slides, I have two particular recommendations.

1. **The 'Electrification and Decarbonization' Scenario should have assumptions supporting an enhanced EWR resource impact in that scenario.** An Electrification and Decarbonization scenario would presumably feature a set of conditions where decarbonization is an enhanced public policy goal, and presumably there would be increased attention, communication, and action by both government and private sector actors to use clean energy resources to achieve GHG reduction. In that spirit, I notice that the E&D scenario includes the assumption of 30% lower costs for renewable resources (wind, solar and storage). However, it would appear that there is no similar assumption of more favorable conditions and uptake for energy efficiency (EWR) as compared to the base case scenario. I would strongly recommend that an E&D scenario include assumptions of more favorable conditions (e.g., lower costs, new and improved efficiency technologies, greater public interest and uptake, etc.) for energy efficiency resources in the modeling. While any 'base case' analysis these days should have a strong energy efficiency contribution, there should be even greater energy efficiency resource selection under an Electrification and Decarbonization scenario.
2. **The 'Electrification and Decarbonization' Scenario should definitely include a monetized 'cost of carbon' in the modeling and analysis to produce a 'proposed resource plan'.** I could not tell from the slides whether the proposed IRP guidelines feature a requirement to include a 'cost of carbon' when performing an IRP analysis. I notice a bullet point on slide 40 that reads: *"Carbon Price Sensitivity?"*, which leads me to infer that there is a question about whether a carbon price will be included as a sensitivity analysis. I would argue that any electric utility IRP these days should include some factor for a carbon cost, but most certainly this should be included in anything referred to as an "Electrification and Decarbonization' scenario. A carbon cost (and other quantifiable related emissions) should be a core component of that scenario, with perhaps an additional 'sensitivity' looking at different levels of carbon cost - - e.g., perhaps a range of the social cost of carbon estimates from the Biden Administration: https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Those are my two recommendations at this point. Thank-you for the opportunity to provide comments.

Martin Kushler, Ph.D.
Senior Fellow, ACEEE

From: James Gignac <jgignac@ucsusa.org>
Sent: Friday, January 7, 2022 3:14 PM
To: Simpson, Naomi (LARA) <SimpsonN3@michigan.gov>; Gibbs, Kayla (LARA) <GibbsK2@michigan.gov>
Cc: Margrethe Kearney <mkearney@elpc.org>; charles griffith <charlesg@ecocenter.org>; Will Kenworthy <will@votesolar.org>
Subject: RE: Stakeholder Feedback - MIRPP & IRP Filing Requirements

Hello Kayla and Naomi,

Apologies for the delay, but we came up with some additional feedback. Here is a point on electric vehicle load assumptions, which relates to point 1 below:

- EV load assumptions should be based on realistic load profiles that consider current customer charging patterns (using both advanced metering infrastructure data and customers subscribed in company programs), as well various managed-charging scenarios for reducing load during peak demand periods.

Also, modeling experts that we've worked with in IRP cases provided some feedback and questions. Here are points by Anna Sommer and Chelsea Hotaling with the Energy Futures Group:

1. EV load - including EV load is going to exacerbate early evening peaks unless managed charging can also be modeled. It would be important to encourage the utilities to model that EV load as something other than just a block of load that increases evening energy consumption.

2. For Scenario 2, we weren't clear how "requires a minimum penetration of wind and solar across the MISO region consistent with MISO Futures 3" would be applied. Does this just apply to the mix of resources needed in the representation of MISO or Zone 7? Or does this dictate the utilities' own system mix as well?

3. Related to that, MISO Futures 3 include a requirement that CO2 is reduced by 80% by 2040, but that's not part of Scenario 2. The rationale for the penetration in newly electrified load in this scenario is arguably a product of the desire to reduce emissions system wide, so why wouldn't the emissions reduction requirement also be included? And similarly, Futures 3 includes some distributed solar, should that be a part of Scenario 2 as well?

4. We wondered if it should be clarified that the ITC needs to be reflected as a reduction in capital and not normalized over the project life?

5. The current rules say "Risk assessment presented with graphics and data that illustrate stochastic risk analysis results in such a way that the probability distributions are clearly conveyed 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." It's hard to do stochastic analysis well and requiring both a detailed explanation for how the probability distributions were derived as well as the workpapers showing how each utility tests for convergence would be really helpful.

6. Finally, the rules require the reporting of revenue requirements. Aurora does not do this automatically, so some post-processing adjustment is needed. We didn't look into this issue for the Consumers IRP because our scope was so limited, but we are not sure if Consumers performed this adjustment or not.

Thank you,

James Gignac
Union of Concerned Scientists

From: O'Meara, Robert <ROMeara@Itctransco.com>
Sent: Wednesday, January 5, 2022 3:22 PM
To: Gibbs, Kayla (LARA) <GibbsK2@michigan.gov>
Cc: Simpson, Naomi (LARA) <SimpsonN3@michigan.gov>
Subject: IRP Filing Requirement Feedback

Good Afternoon Kayla,

Attached you will find the suggestions for the IRP Filing Requirements from ITC (there were a total of three changes). Further, below is just a quick sentence or two regarding our changes/why. Thank you and happy to chat further if needed.

- ITC proposed the following change at the bottom of page 5; because we have experienced a tendency for the LSEs to limit their LOLE analysis to their own service territory rather than consider the entire LRZ 7. Focusing the analysis on estimating LRZ 7 Local Reliability Requirements will allow the Commission and other interested parties to gain better insight on how a particular IRP may affect future Resource Adequacy requirements for the entire Zone."
- ITC proposed the following change(s) on page 17 of the document due to the fact that under current law and during the 2016 energy rewrite it was intended/inferred that the local transmission owner is responsible for all of the transmission analyses and that the LSE is to coordinate with their local transmission owner but might not always be practice. Making this modest change not only allows the full intent of the legislation to be captured but also clarifies specific roles and responsibilities.
- ITC proposed the following change on page 19 of the document in an effort to be more proactive in transmission planning. By the MPSC requesting the local transmission owner to request a forward looking study from MISO, Michigan and its transmission owners will be allowed to plan for the future needs with greater insight, rather than have to adjust in real-time to approved IRPs. Ultimately allowing Michigan, the MPSC, the LSEs and transmission owners the ability to work in greater collaboration for future years greater than 5-years.

Robert O'Meara
Manager, State Regulatory Strategy
romeara@itctransco.com
(C) 517.648.7386
(O) 517.999.2742

EXHIBIT A

DRAFT

Integrated Resource Plan Filing Requirements for December 16th Stakeholder Meeting

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

These application instructions apply to a standard electric utility application for Michigan Public Service Commission (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, 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 a 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. If a

[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.

certificate of necessity (CON) is also being filed, the same filing announcement would serve as the filing announcement 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; and
d) Information related to any CON application that would be filed with the utility's IRP.

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 with 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 proposals (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 with the IRP application documentation demonstrating that the RFP process was completed;
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, and Commission rules;

d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, 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 purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Stakeholder 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; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

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 the 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. Documentation may 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; and

f) Discussion indicating if or how the public outreach process influenced the IRP.

A minimum of two stakeholder engagement workshops are recommended. A stakeholder engagement workshop will provide stakeholders with 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 invite stakeholders, including expected intervenors and the Staff, to its stakeholder engagement workshops.

If the stakeholder engagement workshops are not open to the public, two additional public meetings are recommended. 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 public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advanced notice provided to customers in the utility's service territory. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

If the utility chooses to hold pre-filing workshops, including stakeholder 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 should be maintained on a website in a location open to the public for the duration of the stakeholder 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 analysis of the ~~preferred plan~~ **proposed resource plan** and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the **proposed resource plan** ~~preferred plan~~ and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies for each scenario to determinehow each strategy would perform in an unexpected range of possible futures. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis 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.

For the **proposed resource plan**, the utility's IRP filing shall include a Local Reliability Requirement (LRR) analysis for LRZ 7 per Section 5.2.2.2 of MISO's Resource Adequacy Business Practice Manual. The LRR analysis shall be performed at five-year increments for the entire IRP outlook period. The purpose of this calculation will be to estimate the marginal impact of the utility's **proposed resource plan** on LRZ 7's planning reserve margin, as characterized by the LRR, over the course of the forecast period.

Section XII of this document describes the Transmission Analysis requirements of the utility's IRP filing. The incumbent Transmission Owner (TO) shall perform LRZ 7 Capacity Import Limit (CIL) calculations for each year the utility performs the LRR calculations assuming the utility's **proposed resource plan**.

Estimates of the marginal impact of the utility's **proposed resource plan** on LRZ 7's LRR and CIL determines the marginal impact on the Zone's Local Reliability Requirement which explicitly identifies the amount of internal unforced capacity needed to meet NERC Reliability Standards of a one day in ten years Loss of Load Expectation (LOLE). Out-year transmission topology assumptions will be limited to current MTEP-approved transmission projects.

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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.

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 facilities, 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:

I) For specific supply-side resources (inclusive of storage technologies such as battery storage) of less than 225 megawatt (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators,storage facilities, etc.), that are planned to go into service 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:
        i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
        ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
        iii. 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.
    d) Projected property taxes;
    e) The rates of escalation of cost, including:

i. Capital costs;
ii. O&M costs which are variable and related to fuel;
iii. O&M costs which are variable and unrelated to fuel; and
iv. 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 power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.**
o) **A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling.**

II) Renewable Resources: The utility shall file data consistent with its renewable energy plan. (For incremental renewable energy beyond the 15% requirement in 2021 and any renewable energy to be constructed or purchased after the conclusion of the 20-year renewable planning period ending in 2029, the utility shall file as set forth below.) Revenue requirement and incremental costs of compliance shall be calculated to include the following:

a) Capital, operating and maintenance 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) Ancillary service costs.
e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance.
f) Cost of Contracts.
g) Expenses incurred as a result of governmental action including changes in tax or other laws.
h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.
i) 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); and
j) Provide the following information in relation to renewable resource cost recovery:
    i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
    ii. Forecast through the end of the renewable plan period of the regulatory liability balance.
k) **Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.**
l) **A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling.**

III) Energy Waste Reduction: The utility shall providethe following information in relation to ~~demand response programs,~~ energywaste reduction programs~~, and distributed generation programs~~ cost approval and recovery. For each individual program or group of programs,provide:

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a) Total annual cost including:

   i. Annual O&M cost for each individual portfolio of energy waste reduction~~, demand response~~, and distributed generation programs;

   ii. Annual capital cost for each individual portfolio of energy waste reduction~~, demand response, and distributed generation programs~~; and

   iii. 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;

c) Maximum single event demand reduction;

~~d)~~ Total resource capacity (MW) and type ~~(load modifying resource, emergency demand response, etc.)~~ reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);

e) Total energy reduction achieved (megawatt-hours (MWh)); and

f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) **Demand Response and Distributed Generation Programs: The utility shall provide the following information in relation to demand response programs~~, energy waste reduction programs,~~ and distributed generation programs cost approval and recovery. For each individual program or group of programs, provide:**

a) **Total annual cost including:**

   i. **Annual O&M cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs;**

   ii. **Annual capital cost for each individual ~~portfolio~~ program of ~~energy waste reduction,~~ demand response~~,~~ and distributed generation programs; and**

   iii. **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;

c) **Maximum single event demand reduction;**

d) **Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);**

e) **Total energy reduction achieved (megawatt-hours (MWh)); and**

f) **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 ten 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.

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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 ~~Report 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** ~~preferred resource plan~~ and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisitionstrategy, 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** ~~preferred resource plan~~ and resource acquisition strategy;
c) The data and information requested in the Commission's IRP filing requirements included herein; and
d) Any other information deemed relevant by the utility.

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

I) Executive Summary:

An IRP shall include 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** ~~preferred resource plan~~ and resource acquisition strategy.The executive summary shall summarize the contents of the IRP documentand shall include the following:

a) An overview of the planning period examined in the IRP analysis and application; and

b) A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the goal to be achieved by its proposed course of action and implementation strategy.

II) Table of Contents: Shall be provided **for the contents of the filed case.**

III) Table of Figures: Shall be provided **for the contents of the filed case**.

IV) 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:
    i. Net present value of utility revenue requirements,[2][1] with and without any financial performance incentives for demand-side resources;
    ii. Revenue requirement of existing generation and power purchase agreements;
    iii. Summary of existing generation and power purchase agreements by fuel type;
    iv. Utility's existing capacity resource mix;
    v. Utility's service territory and breakdown of customer class composition; and
    vi. Description of planning period analyzed;
b) Statement of power need;
c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis used in each scenario and sensitivity

[1] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Resultsshould be presented in nominal dollars

evaluated by the utility as part of the IRP process;

d) Market and regulatory environment influencing resource planning decisions:
   i. RTO market and state regulation structure if a multistate utility;
   ii. Potential changes to RTO capacity market;
   iii. Electric customer choice;
   iv. Transmission expansion;
   v. Environmental;
   vi. Renewable portfolio standards; and
   vii. Other;

e) IRP planning process; and

f) Stakeholder report.

V) Analytical Approach:

a) Describe the modeling process, including the duration of the study;

b) Describe and provide a justification for the risk analysis approach adopted from the Risk Assessment Methodology section:
   i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various ~~preferred~~ resource plan options;
   ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan;
   iii. **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.**

c) 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 ~~preferred~~ 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.

d) **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 for the proposed resource plan and any alternative resource plans presented by the utility.**

VI) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities;
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-**XXXXX**, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VII) Existing Supply-Side (Generation) 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) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource;
h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating

costs, etc.);

i) Spot market purchases and off-system sales.

VIII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
    i. Description of current demand response 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;
    ii. **Historic performance of existing demand-side programs and how the utility used such information in its demand response resource decisions;**
    iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response;
    iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

IX) Renewables and Renewable Portfolio Standards Goals:

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 renewable energy credit 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 goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
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.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period;
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio;
    ii. Forecast RECs obtained via Michigan incentive RECs;
    iii. Forecast expected compliance levels by year to meet the renewable portfolio targets;
    iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio;
    v. Identify risks which may drive performance to vary.

X) 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 energy waste reduction 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, and the actions the utility proposes to take in order to achieve that peak demand reduction;

b) Subsections:

   i. Key variables used to develop forecast;
   ii. Long-term forecasting methodology;
   iii. Forecasting uncertainty and risks;
   iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers);
   v. **Base Case**~~Business as usual~~ deliveries and demand forecast;
   vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. **U-XXXXX**, or subsequent Commission orders relating to IRP modeling parameters and requirements.
   vii. **Include detailed information about how the forecasts used for IRP modeling align with forecasts used for distribution planning.**
   viii. **Detail information about distributed energy resource adoption and operation, including distribution connected generation and storage.**
   ix. **Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.**
   x. **Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.**

XI) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. 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.

XII) 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;
b) **In collaboration with their incumbent transmission owner, ~~I~~include an analysis of any transmission system benefits associated with transmission interconnected storage**
c) A detailed description of the utility's efforts to engage local transmission owners ~~in~~**throughout** the utility's IRP process. **In an effort to inform the IRP process and assumptions, a meeting schedule should be set in advance.** The filing should **include the pre-decided meeting schedule, any documentation that supports requested extensions of the initial pre-decided timing**, **and** ~~including~~ a summary of meetings that **ultimately took** place;
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) Any information provided by their local transmission owner~~(s)~~ indicating the anticipated effects of fleet changes proposed in the IRP on LRZ 7's Capacity Import Limit (CIL)~~the transmission system~~, including both generation retirements and new generation, subject to confidentiality provisions;

Any information provided by their local transmission owner~~(s)~~, including cost and timing, indicating potential transmission options that could impactthe utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboringRTOs; (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 ordemand-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 owners, ~~A~~a**ny 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 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** preformed by their local transmission owner **that support the resource plan proposed by the utility.**

i) ~~Include~~ In conjunction with their incumbent 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.**

j) **Provide RTO reports or web links to report locations that contain information relied upon to support model assumptions or other IRP decisions.**

~~j)~~ Upon PCA approval by the Michigan Public Service Commission, the transmission owner shall request the RTO to conduct 20-year forward-looking transmission study on an agreed upon frequency. These studies should identify needed transmission infrastructure to address economic, reliability, and energy adequacy issues arising from anticipated generation additions (including location, scale, and timing) and retirements, as well as load changes due to electrification and growth in energy efficiency and demand response programs, and evaluate resulting GHG emissions reductions achievable in pursuit of

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Michigan's carbon neutral by 2050 goal.

XIII) 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; and
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.

XIV) 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 ~~generation~~ resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. 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 of eachresource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned **resources** ~~generation~~;
b) New build:
    i. New generation technology and operating assumptions;
    ii. New generation development costs;
    iii. New energy integration of storage technology and operating assumptions, **including both long and short duration**

storage;

iv. New energy storage development costs;

v. **Development costs and operating assumptions for combinations of resources constructed as a single facility.**

c) Distributed generation:

i. Solar photovoltaic (including solar plus storage);

ii. Biogas;

iii. Energy storage;

iv. Other distributed generation;

d) Market capacity purchases:

i. Regional market supply outlook;

ii. Availability of market capacity;

iii. Market capacity price assumptions;

e) Long-term power purchase agreements;

f) Transmission resources:

i. Overview;

ii. Existing import and export capability;

iii. Transmission network upgrade assumptions for the IRP; and

iv. Import and export impact on resource strategy.

XV) 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 necessarily exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination);

b) ~~Scenario and sensitivity~~ Results **for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that** include annual revenue requirements, 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;

c) ~~Business as usual/reference~~ **Base** case portfolios options to be selectedfrom;

d) Analysis of IRP results; and

e) Risk assessment **presented with graphics and data that illustrate stochastic risk analysis results in such a way that the probability distributions are clearly conveyed 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.**

XVI) **Proposed Resource Plan**:

Include a detailed description of:

a) The type of energy resource 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 power purchase agreements;

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 proposed course of action.

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

a) Strike an appropriate balance between the various planning objectives specified;
b) Utilize renewable, **storage** and demand-side resources to comply with existing laws and goals and, in the judgment of the utility, are consistent withthe public interest and achieve state energy policies; and
c) In the judgment of the utility, the **proposed resource plan** ~~preferred plan~~, in conjunction with thedeployment of demand response measures, has sufficient resources toserve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the **proposed resource plan** ~~preferred 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 net present value revenue requirement 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 net present value revenue requirement of the utility's proposed **resource** plan and **any** alternative resource plans including the alternative resource plans resulting from theCommission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.
e) **A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning such as distributed energy resources 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.

f) **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.**

g) **A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.**

XVII) Rate Impact and Financial Information:

Projected year-on-year impact of the proposed **resource plan** ~~course of action~~ (and other feasible options) for the periods covered by the plan, covering the followingaccounts:

a) Revenue requirement;
b) Rate base;
c) Plant-in-service capital accounts;
d) Non-fuel, fixed operations and maintenance accounts;
e) Non-fuel, variable operations and maintenance accounts;
f) Fuel accounts;
g) Emissions cost;
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

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 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) Net present value of revenue requirements for the plan;
g) Nominal revenue requirements by year; and
h) Average system rates per kWh by year.

XVIII) Environmental **Considerations and Environmental Justice**:

Describe how the utility's **resource plan and any alternative resource plans presented in the application** ~~proposed IRP~~ 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) **If the Company is proposing retirement of an existing resource, clearly identify the capital cost for environmental regulations and other capital investments in the facility that is avoided capital cost, becomes cost of removal, or is truly avoidable cost.**

~~d) Provide an annual projection of the following emissions for the study period differentiating between existing and new resources within the proposed IRP:~~

- ~~i. Tons of sulfur oxides;~~
- ~~ii. Tons of oxides of nitrogen;~~
- ~~iii. Tons of carbon dioxide;~~
- ~~iv. Tons of particulate matter; and~~
- ~~v. Pounds of mercury.~~

~~e) Provide the total projected emissions of the items listed below through the study period for the utility's proposed plan, as well as the scenarios identified in the MIRPP as approved in Case No. U-18418, or modified by Commission order:~~

- ~~i. Tons of sulfur oxides;~~
- ~~ii. Tons of oxides of nitrogen;~~
- ~~iii. Tons of carbon dioxide;~~
- ~~iv. Tons of particulate matter; and~~
- ~~v. Pounds of mercury.~~

f) **Hold a technical conference with MPSC and EGLE staff within 30 days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.**

g) **Identify, quantify, and provide testimony that compares the expected changes in criteria pollutants, mercury, VOCs, and GHG emissions of the proposed resource plan in the base case to the previously approved build plan in the base case. Illustrate how the proposed resource plan**

will comply with state and federal GHG goals.[2],[3] The previously approved build plan may include a refresh that takes into account the updated load forecast and additional resources to meet any increase in load, but leave the previous base generation assumptions in place. The Company will use a proxy to determine the emissions from MISO purchases and will run the base case scenario with two build plans: the previously approved base build plan and the proposed resource plan.

h) **Analyze multiple build plans, including the proposed resource plan and the optimal build plan from the MIRPP required scenarios to identify and both qualitatively and quantitatively assess the potential impacts to vulnerable communities. This assessment should address water quality, water use, water discharge, waste disposal, air emissions, public health, climate, environmental justice, early retirement, and other considerations that were taken into account in the Company's decision. The Michigan Environmental Justice Screening Tool or equivalent should be used for the identification of vulnerable areas.**

i) **Identify and assess the impact of the proposed resource plan to any non-attainment areas within the electric utility service territory and qualitatively support in testimony. Impacts should consider SO_2 and ozone, as well as their precursors NO_x and $PM_{2.5}$.**

j) **Using the areas identified as vulnerable by the Michigan Environmental Justice Screening Tool, or equivalent (see h) above) complete a more comprehensive evaluation of PM2.5 impacts to these communities, describing expected air quality impacts, including the effect of an early retirement. Conduct dispersion modeling for PM2.5 using standard permit modeling protocols and methods. The base case emissions should be used to establish a baseline modeling demonstration by which to compare the previously referenced least emitting and potential early retirement scenarios in the area where emissions are expected to occur.**

k) **Include metrics to quantify health benefits related to air emission reductions in the scenarios listed above. The following EPA reports and tools provide guidance and are listed in order of preference: the Environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the "Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool" and "Quantifying the Emissions and Health Benefits of Energy Efficiency and Renewable Energy".)".**

l) **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, the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period.**

[2] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) on September 23, 2020, 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.

[3] 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.

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

c) Any modeling input and output files used in developing the application, supporting testimony, **resource plan and any alternative plans** ~~and IRP~~. 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-dependentbinary format should be made available to parties that obtain a license;

d) Cost data**,** ~~and~~ estimates**, and co-benefit analyses** that were used in the resource screening process **or in any other way to deterimine resource selection of** ~~to evaluate~~ each electric resource that was considered either individually or in combination with other resources **constructed as a single facility**, including **distributed energy resources, storage, and** renewable **energy resources.** ~~alternatives, such as solar, wind, or solar plus battery storage~~;

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

f) 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 proceeding;

Updated 8-18-2017

g) 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;

h) 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 utilities generation fleet;

i) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP;

j) A comparison of total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the **base**~~business as usual~~ case;

k) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates;

l) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus battery storage, and such cost estimates for all alternative proposals, solicited or unsolicited, received by the utility;

m) Electricity market forecasts utilized

n) **A stacked bar chart that includes all existing resources and proposed resources color designated by resource type in each of the planning years with the inclusion of a line representing expected load over the length of the planning period.**; and

o) Other documents and data underlying the IRP analysis.

ENVIRONMENTAL LAW & POLICY CENTER
Protecting the Midwest's Environment and Natural Heritage

January 4, 2022

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-21090

Dear Ms. Felice:

The following is attached for paperless electronic filing:

Opening Brief of The Environmental Law & Policy Center, Ecology Center, The Union of Concerned Scientists and Vote Solar

Proof of Service

Sincerely,

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
mkearney@elpc.org

cc: Service List, Case No. U-21090

146 Monroe Ctr St. NW, Ste 422 • Grand Rapids, MI 49503
(312) 673-6500 • www.ELPC.org

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of	)	
CONSUMERS ENERGY COMPANY	)	
for Approval of an Integrated Resource Plan	)	Docket No. U-21090
under MCL 460.6t, certain accounting	)	
approvals, and for other relief.	)	Administrative Law Judge
	)	Sally L. Wallace
	)	

OPENING BRIEF OF THE ENVIRONMENTAL LAW & POLICY CENTER, THE ECOLOGY CENTER, THE UNION OF CONCERNED SCIENTISTS, AND VOTE SOLAR

January 4, 2022

Table of Contents

I. INTRODUCTION

The Environmental Law and Policy Center ("ELPC"), the Ecology Center, the Union of Concerned Scientists ("UCS"), and Vote Solar, (collectively, the "Clean Energy Organizations" or "CEOs") file this opening brief in the above-captioned case. The Michigan Public Service Commission ("MPSC" or "Commission") should issue an order under MCL 460.6t(7) recommending revisions to the Application of Consumers Energy Company ("Consumers" or "the Company") requesting approval of its Integrated Resource Plan ("IRP") and Proposed Course of Action ("PCA").

The Commission should reject the Company's Environmental Justice (EJ) analysis as insufficiently robust and instead recommend that the Company adopt in IRP revisions the analysis conducted by the CEOs' expert witnesses. These witnesses performed an EJ analysis of each plant in the Consumers PCA, quantifying emissions, health impacts, and assessing the demographics of impacted areas. Viewed in the context of the CEOs witnesses' EJ analysis, Consumers has demonstrated that the accelerated retirement of its coal-fired power plants is in the best interest of its customers for economic, reliability, public health, and environmental justice reasons. However, the Environmental Justice analysis does not support the purchase of three affiliate-owned gas-fueled resources. The purchase of those affiliate-owned resources—and in particular Dearborn Industrial Generation ("DIG")—is not only unnecessary to replace the retired capacity, but it would also have deleterious health impacts on Consumers' customers and was procured through a questionable solicitation process. Nor should the Commission permit Consumers to receive regulatory asset treatment to recover the remaining net book balances of the retired coal units in this proceeding, and the Commission should recommend that the Company pursue securitization in a separate proceeding. Additionally, the Commission should reject Consumers' efforts to unjustly profit from contracting for low-cost, third-party renewable resources it already has an obligation to purchase, and recommend that the Company's request for a Financial Compensation Mechanism ("FCM") must be revised to reflect shared savings with customers.

Finally, the Commission should conclude that Consumers' modeling of distributed generation was insufficient and flawed and affirmatively require the Company to study and model behind-the-meter distributed generation resources in its next IRP and to include a low-income component in that study. The Commission should also direct the Company in its next IRP to improve its evaluation of distribution system benefits.

II. HISTORY OF PROCEEDINGS

On June 30, 2021, Consumers filed an application with the Commission for approval of the Company's IRP pursuant to MCL 460.6t and Commission orders and guidance. The Company's application includes accelerated retirement of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 and the replacement of those resources with the purchase of existing gas-fueled resources and expansion of the levels of solar and demand-side resources. Consumers also seeks approval of regulatory asset treatment to recover the remaining net book balances of Karn Units 3 and 4 and Campbell Units 1, 2, and 3 through their current design lives and a finding that the total purchase costs for the existing gas plants are reasonable and prudent for cost recovery purposes. Additionally, Consumers proposes changes to its competitive procurement process, seeks approval of several proposals related to PURPA, and requests a determination that the Company has no PURPA capacity need so long as it is implementing the PCA. Finally, Consumers requests approval of an FCM for any new Power Purchase Agreements ("PPAs") the Company enters into.

A variety of stakeholders petitioned to intervene in the IRP proceeding, including the CEOs, and intervention was granted to all petitioners at the prehearing on July 22, 2021. (1 TR 11, 22). On October 28, 2021, the CEOs filed the direct testimony of eight witnesses. Joe Daniel, Senior Energy Analyst and Manager, Electricity Markets at UCS, presented a strong critique of Consumers' use of the "must-run" designation for coal units. (Daniel Direct, 7 TR 2288, 2292). Will Kenworthy, Regulatory Director, Midwest at Vote Solar, addressed a number of issues, including a discussion of the Company's alignment of resource planning with distribution planning, as well as the flaws in Consumers' consideration and modeling of distributed generation resources. (Kenworthy Direct, 7 TR 2307, 2310-2311). Chelsea Hotaling, a consultant at Energy Futures Group who has reviewed over a dozen IRPs and performed her own modeling in numerous cases, conducted Aurora modeling reflecting Mr. Kenworthy's recommendations for distributed generation. (Hotaling Direct, 7 TR 2301-2302). Alison Waske Sutter, Sustainability and Performance Management Officer at the City of Grand Rapids, provided a municipal and large-client perspective on the plan overall, raising concerns about the Company's acquisition of affiliate-owned Dearborn Industrial Generation ("DIG") and focusing on the need to accelerate to net-zero carbon in an equitable way. (Waske Sutter Direct, 7 TR 2338, 2340-2341). Witnesses Dr. Elena Krieger, Dr. Kelsey Bilsback, and Dr. Boris Lukanov from Physicians, Scientists, and Engineers for Healthy Energy each submitted testimony with a strong technical analysis of equity and environmental issues, examining in detail the public health and energy burden impacts of Consumers' plan. Dr. Krieger describes the proper framework for evaluating public health and equity impacts of the PCA and provides an assessment of those impacts. (Krieger Direct, 7 TR 2363). Dr. Bilsback compiled emissions of fine particulate matter ($PM_{2.5}$) and $PM_{2.5}$ precursors and used two scientific models to translate the emissions from each of these plants to the $PM_{2.5}$ related health impacts. (Bilsback Direct, 7 TR 2396). Dr. Bilsback also filed rebuttal testimony responsive to the Association of Businesses Advocating Tariff Equity ("ABATE") witness Brian

Andrews, addressing the specific environmental and public health impacts from Campbell Unit 3. (Bilsback Rebuttal, 7 TR 2423). Dr. Lukanov evaluates energy cost burdens in Consumers territory, highlights those socio-economic groups that could benefit most from enhanced energy affordability measures, and discusses possible interventions to increase residential energy affordability and lower energy cost burdens. (Lukanov Direct, 7 TR 2433). Synia Gant-Jordan, a resident and community leader in Grand Rapids, provided a voice from the community, explaining her participation in meetings with Dr. Krieger and confirming that the topics in Dr. Krieger's testimony were related to many ongoing concerns in the black and brown community in Grand Rapids. (Gant-Jordan Direct, 7 TR 2453).

III. APPLICABLE LEGAL STANDARDS

Michigan statutes, caselaw, and Commission orders create a framework for evaluating and approving Consumers' IRP. Utilities are periodically required to file IRPs under Section 6t of 2016 PA 341 ("Act 341"), MCL 460.6t, and Consumers timed its filing to comply with the settlement agreement that resolved its last IRP in U-20165. (Dkt. No. U-20165, June 7, 2019 Order at 90). In its Order approving that 2019 settlement, the Commission observed that the settlement's requirement that Consumers file in June 2021 provided the Commission with "an opportunity to revisit many of these same issues with the benefit of additional analysis and information about the accuracy of past projections." *Id*. Consumers must also comply with the Commission's November 21, 2017, order in Case No. U-18418, Exhibit A, which approved the Michigan Integrated Resource Planning Parameters (MIRPP) and the Commission's December 20, 2017, order in Case No. U-18461, Attachment A, which approved the Integrated Resource Plan Filing Requirements (IRP Filing Requirements). Since Act 341 was passed, the Commission has considered IRPs filed by each of Michigan's regulated electric utilities.

The very first section of the IRP statute (subsection (1)) requires the Commission to commence a proceeding every five years and, in consultation with the Michigan agency for energy, the department of environmental quality (now EGLE), and other interested parties, to accomplish a number of tasks. Among these tasks are several relevant to protection of public health and the environment. Subsection (1)(c) requires the Commission to "[i]dentify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state." MCL 460.6t(1)(c). Subsection (1)(d) requires the same with respect to formally proposed, but not yet approved, regulations, laws or rules. These state and federal environmental regulations, laws, or rules must be incorporated into modeling scenarios and assumptions. MCL 460.6t(f)(ii). While the statute is prescriptive with respect to existing or formally proposed environmental regulations, laws, or rules, it does not limit the degree to which emissions of pollutants and their attendant environmental and public health concerns can and should be considered by the Commission.

Indeed, the Commission is required under subsection (7) to request an advisory opinion from EGLE "regarding whether any potential decrease in emissions of sulfur dioxide, oxides of nitrogen, mercury, and particulate matter would reasonably be expected to result if the integrated resource plan proposed by the electric utility . . . was approved and whether the IRP can reasonably be expected to achieve compliance with the regulations, laws, or rules identified in subsection (1)." MCL 460.6t(7). Subsection (7) squarely puts before the Commission in an IRP the question of emissions of pollutants from resources included in the plan.

Michigan statutes permit the Commission to approve an IRP only if the Commission finds that the IRP provides "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." MCL 460.6t(8)(a). In making this determination, the Legislature has instructed the Commission to consider whether the plan "appropriately balances" (1) resource adequacy and capacity to serve anticipated peak load; (2) compliance with applicable state and federal environmental regulations, (3) competitive pricing, (4) reliability, (5) commodity price risks, (6) diversity of generation supply, and (7) whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective. MCL 460.6t(8)(a)(i)-(vii).

The Commission must consider environmental justice, including public health and energy burden impacts, when evaluating an IRP. On August 20, 2020, the Commission opened a docket directing Commission Staff to form a collaborative group to review and discuss improvements and ways to better align integrated resource planning and distribution planning, and to coordinate with EGLE on the inclusion of public health and environmental justice considerations in future integrated resource planning cases. (U-20633, August 20, 2020 Order at 5). In that 2020 docket, the Commission referenced its decision in the DTE IRP case, docket U-20471. In that IRP case, MEC/NRDC/SC provided compelling evidence on the public health impacts from fossil-fired generation, and the Administrative Law Judge agreed that "public health impacts, to the extent these impacts can be identified, assigned, and the associated costs quantified, should be recognized as part of the retirement analysis in future IRPs." (Dkt. No. U-20471, February 20, 2020 Order at 41, quoting PFD at 123). In its Order, the Commission acknowledged the argument under the Michigan Environmental Protection Act ("MEPA") raised by MEC/NRDC/SC and supported by public health data, and agreed that MEPA does apply to Commission approval of IRPs. (Dkt. No. U-20471, February 20, 2020 Order at 43). However, in that DTE IRP case, the Commission concluded that the IRP did not result in the "pollution, impairment, or destruction of the air, water, or other natural resources" necessary to establish a *prima facie* case under MEPA, and also found that there were no feasible alternatives to DTE's IRP. (Dkt. No. U-20471, February 20, 2020 Order at page 45-46). The Commission did state that: "In future IRP proceedings, the Commission expects to coordinate with EGLE on the inclusion of public health and environmental justice considerations as part of the environmental information EGLE shares with the Commission under Section 6t. Public health impacts are inherent in EGLE's responsibilities as an environmental regulator, as many laws, rules, and permitting requirements are tied back to health and environmental indicators." (Dkt. No. U-20471, February 20, 2020 Order at 46). In its order, the Commission resisted the quantification of public health impacts, and raised questions about whether the expertise for such quantification was available at the Commission. (Dkt. No. U-20471, February 20, 2020 Order at 47). However, the Commission also "[noted] that the Michigan Inter-Agency Environmental Justice Response Team was created by Governor Whitmer, and the Commission anticipates that additional guidance in this area may be forthcoming from this task force after considering stakeholder input through the newly created Michigan Advisory Council for Environmental Justice." (Dkt. No. U-20471, February 20, 2020 Order at 47).

On September 23, 2020, Governor Whitmer issued Executive Directive ("ED") 2020-10 and Executive Order ("EO") 2020-182, which announced the "MI Healthy Climate Plan." Governor Whitmer explained that: "Carbon-neutrality is needed not only for the environment and public health, but also for the resilience of our economy." ED 2020-10. Governor Whitmer issued eight directives, one of which related specifically to IRPs:

> The Department [of Environment, Great Lakes, and Energy, ("Department")] must expand its environmental advisory opinion filed by the Department in the Michigan Public Service Commission's ("Commission") Integrated Resource Plan (IRP) process under MCL sections 460.6t and also file environmental advisory opinions in IRPs filed under MCL 460.6s. The Department must evaluate the potential impacts of proposed energy generation resources and alternatives to those resources, and also evaluate whether the IRPs filed by the utilities are consistent with the emission reduction goals included in this Directive. **For advisory opinions relating to IRPs under both MCL 460.6s and MCL 460.6t, the Department must include considerations of environmental justice and health impacts**

> **under the Michigan Environmental Protection Act.** The Commission's analysis of that evidence must be conducted in accordance with the standards of the IRP statute and the filing requirements and planning parameters established thereto.

(Emphasis added.) The Commission evaluated its obligations under this ED in a multi-captioned docket that encompassed implementation of Act 341 as well as the Commission's own commencement of a collaborative to consider issues related to integrated resource and distribution plans. (Dkt. Nos. 20633, 15896, 18418, 18461, hereinafter "U-20633 *et al.*") The Commission issued an order in those dockets on February 18, 2021, describing the development by Commission Staff of a recommendation to the Commission of how to implement the Governor's ED 2020-10. Staff recommended incorporation of the ED by updating the MIRPP and IRP filing requirements, which would be the subject of a stakeholder process to be completed in 2022. (U-20633 *et al.* at 6). The Commission considered two options for near-term filings, that would occur before completion of the 2022 stakeholder process, and approved both with some changes.

Because Consumers' IRP was filed prior to the stakeholder process, Staff asked Consumers to do a qualitative, rather than quantitative analysis of environmental justice indicators. Staff witness Kolioupoulos described the process between Consumers, EGLE, and Staff regarding how the Company could incorporate Environmental Justice in its IRP filing. (Kolioupoulos Direct, 8 TR 3596). Witness Kolioupoulos testified: "Due to the short timeframe and work that the Company had already done on its IRP, it was decided that a more qualitative analysis would be sufficient until the Michigan Integrated Resource Planning Parameters (MIRPP) are updated during the MI Power Grid Phase III process yet to commence." (Kolioupoulos Direct, 8 TR 3595). Staff's decision to require a limited, qualitative analysis appears to set a very minimum bar, below which the Company would clearly have avoided the most basic of efforts to consider Environmental Justice as required by the ED. The decision appears rooted in the availability of resources and time to complete a more quantitative Environmental Justice analysis. It does not, however, preclude intervenors from conducting a more quantitative Environmental Justice analysis and providing it to the Commission for consideration in the Company's IRP. Nor would it prevent the Commission, which has the ultimate responsibility for approving or denying an IRP, from considering a more robust set of credible information submitted to the record.

Under MCL 460.6(t)(7), no later than 300 days after the filing of the application, the Commission has the option of recommending changes to the Company's PCA. Those recommendations would initiate a 15-day comment period on the recommended changes. The utility has 30 days from the 300-day order recommending changes to decide whether to submit a revised IRP, and the Commission has 60 days from the 300-day order to decide whether to approve or deny the IRP. If the Commission denies a utility's IRP, the utility, within 60 days after the date of the final order denying the IRP, may submit revisions to the plan to the Commission for approval and the Commission commences a new contested case hearing. If the submitted revisions are not substantial or inconsistent with the original IRP, the Commission must either approve or deny, with recommendations, the revised IRP within 90 days. If the revisions are substantial or inconsistent with the original integrated resource plan, the commission has up to 150 days to issue an order approving or denying, with recommendations, the revised IRP. MCL 460.6t(9).

IV. BURDEN OF PROOF

Consumers bears the burden of proof to demonstrate by a preponderance of the evidence that its IRP is the most reasonable and prudent means of meeting its energy and capacity needs, and that the Company is entitled to any relief requested. *BCBSM v Governor*, 422 Mich 1, 88-89; 367 NW2d 1 (1985); *In re Detroit Edison Co*, MPSC Case No. U-8030-R, Opinion & Order dated July 9, 1987, pp 16-17. Preponderance of the evidence means "such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth." *People v. Pugh*, 48 Mich. App. 242, 245 (1973). While the burden of going forward shifts between parties as a proceeding progresses, the burden of proof never shifts away from the applicant. *In re the Application of Upper Peninsula Power Company for approval of its integrated resource plan,* MPSC Case No. U-18404, Opinion & Order dated June 7, 2019, at 6.

V. THE COMMISSION SHOULD ADOPT THE ENVIRONMENTAL JUSTICE MODELING SUBMITTED BY EXPERTS KRIEGER AND BILSBACK

A. The Company's PCA inadequately accounts for environmental justice and public health.

Consumers' Environmental Justice analysis was insufficiently robust. CEOs witness Waske Sutter testifies that this was a missed opportunity for Consumers to "establish a best-in-class approach to addressing environmental justice by modeling the plan's impacts on communities of color and low-income communities." (Waske Sutter Direct, 7 TR 2353). Witness Waske Sutter testified that, while she appreciated Consumers recognizing opportunities for the Company and the Commission to consider public health, "the Commission should encourage a more robust analysis of environmental justice than that provided by Consumers' witness Breining." (Waske Sutter Direct, 7 TR 2352). Company witness Breining agrees to some degree with Ms. Waske Sutter's testimony, indicating that the Company supports working with EGLE and MPSC Staff to develop "a standard framework to evaluate EJ matters for future IRPs" but also insisting that the Company's Environmental Justice analysis was sufficient for this IRP. (Breining Direct, 8 TR 1381).

IRPs have the potential to both directly and indirectly impact energy equity and public health across the State of Michigan, but many of these impacts have not historically been considered in depth. (Krieger Direct, 7 TR 2361). CEOs witness Dr. Krieger testifies that

Consumers' analysis provided a limited health impact analysis based on standardized pollutant-impact emission factors. (Krieger Direct, 7 TR 2369). Company witness Breining, who was responsible for the Company's environmental justice analysis, explains that the Company's analysis consisted of looking at the U.S. EPA's EJSCREEN tool to identify facilities that were above the 75th percentile in an Environmental Justice Index, and by that standard considered to be vulnerable communities. (Breining Cross, 6 TR 1386, 1364). Because three of the four existing gas plants the Company proposes to acquire (DIG, Covert, and Kalamazoo River) were above the 75th percentile, witness Breining explains that the Company compared the PCA to an "alternate plan" that did not include the purchase of the four gas plants. (Breining Direct, 6 TR 1365). This comparison, however, did not include any analysis of the four gas plants on an individual basis. (Breining Cross, 6 TR 1391:3 - 1392:3).

During cross examination when questioned about the Company's use of the EPA EJSCREEN tool, Company witness Breining testified that the Company had a call with Staff and EGLE in April and agreed to form some type of EJ analysis for the IRP. The Company looked at different tools for the analysis "and only felt comfortable running this one [the EPA EJSCREEN] given our -- the lack of time and the lack of expertise that the Company had to perform the analysis." (Breining Cross, 6 TR 1414). Ms. Breining does not put herself forth as an expert on environmental justice analyses, testifying: "I am not an EJ or health screen analyst or expert so I cannot speak to the exact health benefits or health detriments of these emissions" (Breining Cross, 6 TR 1396:5-7); ". . . again I'm not an expert on the EPA designed tool. This was just a tool that we used at the request of Staff and EGLE." (Breining Cross, 6 TR 1403:25-2). And while Dr. Krieger also used a proxy index to provide an example for how the soon-to-be-released Michigan EJ Index tool can be applied to the IRP process, she recognized that "[t]he overall index should not necessarily be applied in all cases, however, because individual indicators can provide valuable information on their own as well." (Krieger Direct, 7 TR 2378). Consumers used the EJSCREEN as an initial tool but lacked careful consideration of the information provided by the many indicators that go into creating each of the indices. Indeed, witness Breining was not even clear on the difference between an index and the indicators used to create them until the difference was pointed out to her on cross examination. (Breining Cross, 6 TR 1427). When asked about how she made the decision to look to indexes rather than to individual indicators, as Dr. Krieger explained can contain valuable information, Company witness Breining testified:

> I don't believe we got into that detail, we just followed the EPA tool. Like we really know very little about this tool. Again, this was a good-faith evaluation that the Company did, we were not required to perform this analysis, and we had concerns over not having the expertise to perform these analyses for this IRP, but since it was not a requirement, we acted in good faith with Staff and EGLE and performed this analysis, and we simply used this index table on the first page of each report based on knowing that this is the overall score that is given per the EPA calculations.

(Breining Cross, 6 TR 1428:6-16).

Ms. Breining herself did not reach out to any members of the community around DIG—a unit she agreed exceeded the EJSCREEN index the Company was using—and was not made aware of any information gleaned in public outreach sessions. (Breining Cross, 6 TR 1413). Ms. Breining is also not aware that any changes to the plan were made as a result of her Environmental Justice analysis. (Breining Cross, 6 TR 1413:14-17). In contrast, Dr. Krieger met with community members in Grand Rapids, the largest city in Consumers territory. One of these community members, Synia Gant-Jordan, testified that she had an opportunity to review Dr. Krieger's testimony and felt that it was "on-point with so many of the concerns that we face on a day to day basis in our black and brown communities." (Gant-Jordan Direct, 7 TR 2453).

B. The Commission should look to the analysis of Drs. Krieger, Bilsback, and Lukanov when evaluating the Environmental Justice impact of the Company's PCA.

1. The CEOs sponsored the testimony of three well-qualified expert witnesses who discussed the public health and equity impacts of the Company's IRP.

The CEOs sponsored the testimony of three expert witnesses from Physicians, Scientists, and Engineers for Healthy Energy. Dr. Elena Krieger—who has significant experience analyzing the intersection of clean energy adoption, deep decarbonization, public health, energy equity, and resilience—provided a framework to evaluate the public health and equity impacts of Consumers' IRP, and then provided an assessment of those impacts. (Krieger Direct, 7 TR 2361). Dr. Krieger has recently worked on projects characterizing environmental justice, air quality, emissions, and public health metrics of peaker power plants across nine states to identify optimal targets for replacement with energy storage; analyzing solar adoption rates in disadvantaged communities in California; analyzing where power sector carbon emission reductions will have the greatest public health benefits in Ohio and Pennsylvania; integration of public health and energy equity metrics such as affordability and resilience into deep decarbonization modeling for New Mexico, Colorado, and Nevada; and ongoing work designing and optimizing deployment of solar-plus-storage to create resilience hubs in vulnerable communities across California. (Krieger Direct, 7 TR 2362).

Dr. Kelsey Bilsback—who has a background in mechanical engineering and atmospheric science—quantified the public health and equity dimensions of gas, coal, and biomass-fired power plants in the PCA. (Bilsback Direct, 7 TR 2395). Dr. Bilsback has expertise in emissions, aerosols, air pollution, air quality measurements, atmospheric modeling, and data and statistical analyses, and has, among other things, worked on implementing process-level models for secondary organic aerosol in atmospheric models and using chemical-transport models to assess the air quality, health, and climate impacts of energy transition policies. (Bilsback Direct, 7 TR 2394).

Dr. Boris Lukanov—whose research focuses on energy equity, energy efficiency, air quality and energy resource modeling and optimization—evaluates which socio-demographic groups in Consumers' territory could benefit most from enhanced energy affordability measures and discusses possible ways to lower energy cost burdens. (Lukanov Direct, 7 TR 2432-33). Dr. Lukanov has co-authored technical reports and peer-reviewed papers on equity-focused climate strategies, equitable access to clean energy, and energy transition pathways for various states. (Lukanov Direct, 7 TR 2432). He is currently leading a technical analysis on energy cost burden and energy affordability for the Colorado Energy Office. (Lukanov Direct, 7 TR 2432).

2. **Drs. Krieger and Bilsback provided credible testimony on the environmental and public health impacts of resources in the PCA.**

CEOs witnesses Drs. Krieger and Bilsback used well-known methods for identifying opportunities to reduce environmental burdens in polluted and vulnerable communities and to increase energy affordability and access in historically underserved communities. Dr. Krieger explained that for a robust environmental justice analysis, utilities should first quantify emissions from each existing and proposed unit, on a unit-by-unit basis. (Krieger Direct, 7 TR 2371). Second, utilities should evaluate the public health impacts of those emissions. (Krieger Direct, 7 TR 2371). As an initial matter, $PM_{2.5}$ is a pollutant that can easily be studied. Dr. Krieger also explains the value in calculating the total health impacts of a given power plant or a given scenario, as well as the rate of health impacts per megawatt-hour or gigawatt-hour of generation. These calculations are most easily conducted for power plants owned by or directly contracted by the utility, and were performed by Dr. Bilsback.

Ms. Krieger also suggests completing a population proximity analysis to assess who lives near (or downwind) from power plants in the IRP. A simple version of this analysis consists of evaluating demographic metrics for populations living within a given radius of a power plant. Dr. Krieger conducted such an analysis by using the three-mile radius (the "buffer zone") used within the EPA's Power Plants and Neighboring Communities Tool. (Krieger Direct, 7 TR 2372). She then calculated the total population living within the three-mile buffer zone around the plant, compared specific metrics for this population—such as number of low-income households and households of color—to the rest of the state, and then evaluated cumulative socioeconomic and environmental health burdens for this population using environmental justice screening tool data. These population data can be coupled with the emissions and health impacts data described previously to identify where a plant may be contributing to high cumulative burdens on a given community. (Krieger Direct, 7 TR 2373). In comparison, witness Breining testified that population data "did not impact" her analysis. (Breining Cross, 6 TR 1407:16-19).

Dr. Krieger emphasized that Consumers should consider the public health impacts and environmental equity metrics for each plant individually when developing its plan to determine which plants should be phased out and retired first as it transitions to clean energy and develops its greenhouse gas reduction strategy. (Krieger Direct, 7 TR 2384). Dr. Bilsback performed her analysis on a unit-specific basis. (Bilsback Rebuttal, 7 TR 2424). That is because individual metrics can help balance the resource portfolio in such a way that Consumers can reduce mortality impacts and reduce historic disparities in environmental public health impacts of the power plants in its portfolio, the power plants it plans to purchase, and the power plants with which it contracts. (Krieger Direct, 7 TR 2384). Consumers witness Breining was very clear that the Company's analysis of gas units located in vulnerable communities only compared the proposed course of action to the “alternate plan”— excluding the gas units—but never looked at plants on an individual basis. (Breining Cross, 6 TR 1391:3 - 1392:3). Witness Breining confirmed that nowhere in her workpaper did she break out the individual emissions of the proposed gas plants. (Breining Cross, 6 TR 1392:21-24).

In stark contrast to Consumers’ analysis, CEOs witness Dr. Bilsback quantified the public health and equity dimensions of gas, coal, and biomass-fired power plants in Consumers IRP. (Bilsback Direct, 7 TR 2395). Dr. Bilsback used two well-known models to evaluate the $PM_{2.5}$-related health impacts of the power plants in the Consumers IRP. The first model was the U.S. EPA’s CO-Benefits Risk Assessment Health Impacts Screening and Mapping Tool, or COBRA. This model was first released in 2001, has precedent for use in policy decisions, and has been implemented widely in the scientific literature. COBRA uses emissions data for pollutants that include $PM_{2.5}$, NO_x, SO_2, and VOCs and physical information about a source (e.g., stack height, fuel type) as inputs. Then, COBRA conducts a series of scientific calculations to translate the information about the source and emissions to a marginal change in annual-averaged atmospheric $PM_{2.5}$. (Bilsback Direct, 7 TR 2399). The second model was the Intervention Model for Air Pollution (“InMAP”). This model is an independent air quality model that has been published in the peer-reviewed scientific literature. InMAP uses pre-processed chemical and meteorological information from a state-of-the-science atmospheric model to estimate the marginal impacts of an emissions source on annual-averaged atmospheric $PM_{2.5}$. InMAP integrates demographic data, providing the opportunity to quantify the spatial and environmental justice impacts of emissions shifts. (Bilsback Direct, 7 TR 2400).

Dr. Bilsback estimated the total emissions, rate of emissions, and fine particulate matter ($PM_{2.5}$)-related health impacts of nine total plants. In her rebuttal testimony, Dr. Bilsback explains that while she presented information in her testimony as a whole, rather than by unit, her analysis of emissions was conducted on a unit-by-unit basis, and that the emissions from each unit was produced in discovery in her workpapers. (Bilsback Rebuttal, 7 TR 2424, discussing Campbell Unit 3). Dr. Bilsback was able to perform this unit-by-unit analysis because she obtained data from a variety of sources, including EGLE and EPA. (Bilsback Direct, 7 TR 2402). And while Company witness Breining argues that the self-reported data the Company used is "more reliable," she provides no explanation of why, and testified that she never conducted a plant-by-plant analysis. (Breining Rebuttal, 6 TR 1378).

The Commission should find that Dr. Bilsback provides a credible analysis of emissions rates for the plants addressed in Consumers PCA and adopt the analysis of Dr. Bilsback and Dr. Krieger as the appropriate Environmental Justice analysis in this case.

3. Dr. Lukanov provided credible testimony on energy burden from the PCA.

Dr. Lukanov's testimony provided a framework for evaluating energy cost burden across Consumers utility service territory, discussed why energy cost burden and energy affordability should be important considerations in IRPs, highlighted which socio-demographic groups within Consumers territory could benefit the most from enhanced energy affordability measures, and discussed possible interventions to increase residential energy affordability and lower energy cost burdens. (Lukanov Direct, 7 TR 2433).

Dr. Lukanov calculates energy cost burden using a simple equation: household annual fuel consumption is multiplied by fuel prices to calculate household energy spending, which is divided by the household income to obtain the fraction of household income spent on residential energy needs. (Lukanov Direct, 7 TR 2435). Because of the unavailability of granular residential energy consumption data, Dr. Lukanov estimated average residential energy use by census tract and fuel type using a regression model based on a variety of geographic, demographic, housing-related, and climate variables. (Lukanov Direct, 7 TR 2435). Dr. Lukanov found that energy cost burdens are highest in rural areas when all fuels are considered, but when looking at electricity only, urban areas tend to be the most burdened. (Lukanov Direct, 7 TR 2438).

Dr. Lukanov analyzed how energy burden related to household characteristics, finding that energy burdens tend to increase significantly for lower income groups and communities of color and tend to be higher in urban areas where a greater proportion of the population rents and in areas with a higher fraction of communities of color. (Lukanov Direct, 7 TR 2441). Rural areas tend to have both higher energy cost burdens and higher energy consumption overall. (Lukanov Direct, 7 TR 2441).

Putting this in the context of an IRP, Dr. Lukanov explains that his findings imply that "decarbonization pathways within IRPs that solely focus on greenhouse gas emissions reductions (i.e., on energy use and fuel type) and on total resource costs may end up benefiting less economically vulnerable (wealthier) populations if there are no provisions to explicitly target low-income households, renters, and people of color, and may therefore exacerbate existing inequities." (Lukanov Direct, 7 TR 2443:4-9). Dr. Lukanov also suggests that more investment in low-income energy waste reduction programs may be needed in Michigan's most energy-burdened communities, such as Flint and Saginaw, and that low-income households stand to benefit from electrifying propane heating, provided actions are taken to ensure that electrification does not drive up system costs. (Lukanov Direct, 7 TR 2443). Dr. Lukanov testifies that: "Systemic and structural inequities have historically contributed to disparities between racial and ethnic groups, ranging from federal government-sponsored segregation in housing to discriminatory lending practices and redlining. All this is to emphasize that aside from low-income households in general, renters and communities of color, particularly Black communities, would benefit from energy cost burden interventions being integrated into the Consumers IRP process." (Lukanov Direct, 7 TR 2445:2-7). Dr. Lukanov's testimony is underscored by Grand Rapids resident and community advocate Synia Gant-Jordan:

> Energy prices have been an ongoing issue in the black and brown community. It impacts the health of these communities, because it creates a lot of anxiety and a lot of work to try to keep utilities on in our households so that our families can thrive. This is even harder for single parent households, like my mother. I want the Commission to understand that black and brown communities have been struggling for years on so many fronts, and that being able to afford energy should not be one of them. I want our black and brown communities to be able to participate and invest in energy efficiency programs, invest in more efficient appliances and homes, and have the opportunity to install solar panels. I don't feel like our communities have had a real opportunity to engage in these programs and take advantage of clean energy and energy efficiency. The BIPOC communities should be the first to be invested in for solar, not the last. This investment needs to be something that benefits the community and is an investment in the community, not just the utility. As a real estate agent I know how important energy costs are for home buyers, and sometimes energy bills can be a barrier to home ownership.

(Gant-Jordan Direct, 7 TR 2453:21-2454:11). These concerns are echoed by Sergio Cira-Reyes, the Climate Justice Catalyst at Urban Core Collective ("UCC"). UCC is well suited to providing these insights to the Commission, given that the non-profit's "expertise lies in explaining complex institutions and systems of power to local communities and in gathering input about how these institutions and systems can better address community needs." (Cira-Reyes Direct, 7 TR 2476). Mr. Cira-Reyes explains the energy burden for low-income households and testifies that he has seen members of his community having to make tradeoffs because energy costs make up such a large share of their income. (Cira-Reyes Direct, 7 TR 2488:3-22). Mr. Cira-Reyes discusses how low-income communities bear disproportionate burdens related to reliability problems and to pollution from energy generation. (Cira-Reyes Direct, 7 TR 2490:8-2492:4). Ms. Waske Sutter also raises concerns related to the impact of Company programs on the most vulnerable members of the Grand Rapids community. (Waske Sutter Direct, 7 TR 2357).

Dr. Lukanov explains that energy cost burden provides a useful and quantifiable way of thinking about energy affordability, and it should be considered by utilities as part of their IRPs. Utilities can analyze how their proposed plan may impact energy cost burdens borne by various segments of their customer population. (Lukanov Direct, 7 TR 2446). Because utilities have more access to customer information than outside parties, they would be able to conduct a more accurate and detailed analysis within the framework that Dr. Lukanov describes. (Lukanov Direct, 7 TR 2446-2447). Dr. Lukanov recognizes that other proceedings, such as rate cases, play an important role in assessing energy cost burdens, but the Commission should not underestimate the degree to which the portfolio approved in an IRP includes multiple factors that can influence energy cost burdens, such as overall spending, energy efficiency, and distributed solar. (Lukanov Direct, 7 TR 2447). Like witnesses Gant-Jordan and Cira-Reyes, Dr. Lukanov testifies that while energy efficiency reduces energy burdens, and can create substantial savings for the most cost-burdened households, there are many obstacles to low income and BIPOC communities participating in these programs. (Lukanov Direct, 7 TR 2448). He recommends considering low-income energy efficiency as a separate resource in an IRP, and also suggests more significant consideration of distributed, rooftop solar programs as an IRP resource for low-income customers, such as the program evaluated by witnesses Kenworthy and Hotaling. (Lukanov Direct, 7 TR 2448-2449; Kenworthy Direct, 7 TR 2327).

C. Fossil fuel combustion in power plants emits air pollutants that have negative and inequitable impacts on air quality and human health.

Consumers does not dispute that $PM_{2.5}$ has a negative impact on human health. (Breining Cross, 6 TR 1422:11-16). Pollutants from fossil fuel plants include harmful pollutants emitted directly by the plants, or "primary air pollutants," and other emissions that react chemically in the atmosphere and form harmful air pollutants downwind from the power plant, or "secondary air pollutants." (Bilsback Direct, 7 TR 2397-2398). The primary air pollutant Dr. Bilsback addresses is $PM_{2.5}$. (Bilsback Direct, 7 TR 2397-2398). Dr. Bilsback also analyzes nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOCs), which can chemically react to form ozone and $PM_{2.5}$. (Bilsback Direct, 7 TR 2398).

Children, the elderly, people with underlying health conditions (such as asthma), and people with higher cumulative socioeconomic, health, and environmental burdens, are particularly susceptible to the effects of air pollution. (Bilsback Direct, 7 TR 2398). Because air pollution can be transported over long distances, it can impact both people who live near emissions source as well as farther away. (Bilsback Direct, 7 TR 2398). Dr. Bilsback explained that there are numerous air quality models that are widely used to represent $PM_{2.5}$. These models use scientific methods to estimate the air quality and health impacts of emissions sources, taking into account factors including the amount of emissions from a source, the physical characteristics of the emissions source, meteorology, atmospheric chemistry, and the epidemiological relationship between $PM_{2.5}$ and human health. Using one such model, Dr. Bilsback provided a table (Table 1) with total emissions from each plant in the Consumers PCA, as well as a table (Table 2) with emissions rates, reflecting which plants have the highest emissions per unit of energy generated or heat input (for steam producing plants). (Bilsback Direct, 7 TR 2403). Table 2 shows that plants that have lower total emissions may still have higher emission rates, "indicating that taking that plant offline would displace a larger proportion of overall emissions per energy produced." (Bilsback Direct, 7 TR 2403). Tables 1 and 2 are reproduced on the following page:

Table 1: Total emissions per year of fine particulate matter ($PM_{2.5}$), sulfur dioxide (SO_2), nitrogen oxides (NO_x), volatile organic compounds (VOCs), and carbon dioxide (CO_2). Energy production per year in gross load and steam load. Emissions are from 2019 and are summed across units. Data are given in gigawatt-hours, 1,000 lbs, and metric tons.

Power Plant	Gross Load (GWh)	Steam Load (1,000 lbs)	$PM_{2.5}$ (tons)	VOCs (tons)	NO_x (tons)	SO_2 (tons)	CO_2 (megatons)
Dan E Karn[C, G]	1,976	690,359	47	2.9	557	516	2.0
J H Campbell[C]	9,025		538	13	2,918	5,244	8.2
Jackson Generating Station[G]	2,237		0.8	10	504	4.7	0.9
Zeeland Generating Station[G]	4,162		2.6	20	197	8.8	1.7
Midland Cogeneration Venture[G]	7,316	93,545	3.3	33	3,524	21	4.0
Kalamazoo River Generating Station[G]	60		0.6	0.5	17	0.2	0.04
Livingston Generating Station[G]	13		1.2	0.1	22	0.1	0.01
New Covert Generating Project[G]	7,616		71	34	177	14	2.8
Dearborn Industrial Generation[G,O]	3,665	4,614,373	70	20	535	610	1.9

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Table 2: Emissions rates of fine particulate matter ($PM_{2.5}$), volatile organic compounds (VOCs), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and carbon dioxide (CO_2). Data are from 2019 and are summed across units. Values are in metric tons per terawatt hour of gross load or metric tons per metric trillion British thermal units (tons/MTBtu), to account for both electricity and steam production in the emissions rates.

Power Plant	$PM_{2.5}$ (tons/TWh)	VOCs (tons/TWh)	NO_x (tons/TWh)	SO_2 (tons/TWh)	CO_2 (megatons/TWh)
J H Campbell[C]	60	1.5	323	581	0.9
Jackson Generating Station[G]	0.3	5	225	2.1	0.4
Zeeland Generating Station[G]	0.6	4.8	47	2.1	0.4
Kalamazoo River Generating Station[G]	9.2	8.3	278	3.4	0.7
Livingston Generating Station[G]	93	8.5	1,724	4.3	0.8
New Covert Generating Project[G]	9.3	4.5	23	1.8	0.4
Power Plant	**$PM_{2.5}$ (tons/MTBtu)**	**VOCs (tons/MTBtu)**	**NO_x (tons/MTBtu)**	**SO_2 (tons/MTBtu)**	**CO_2 (megatons/MTBtu)**
Dan E Karn[C, G]	2.2	0.1	26	24	0.1
Midland Cogeneration Venture[G]	0.04	0.4	44.8	0.3	0.1
Dearborn Industrial Generation[G,O]	1.5	0.4	12	14	0.04

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Table 1 shows that all nine power plants, including coal and gas plants, have health-damaging emissions. The JH Campbell coal plant has the highest *total* emissions of $PM_{2.5}$ and SO_2. Retiring this plant would eliminate 538 metric tons of $PM_{2.5}$, 13 metric tons of VOCs, 2,918 metric tons of NO_x, 5,244 metric tons of SO_2, and 8.2 megatons of CO_2 per year. The Karn units also had higher *total* $PM_{2.5}$ and SO_2 emissions than the natural gas plants that Consumers already owns or purchases power from (i.e., Jackson, Zeeland, Midland). The Midland gas plant has the highest NO_x emissions overall—a pollutant that has both primary health impacts and contributes to the formation of ozone and $PM_{2.5}$. Covert and Dearborn have the highest emissions out of the four plants that Consumers has proposed purchasing. In fact, the Dearborn gas plant has higher annual emissions than the Karn plant for all pollutant types analyzed except NO_x and CO_2. Depending on how Dearborn is operated, this plant may offset much of the emissions benefits from retiring Karn early. (Bilsback Direct, 7 TR 2405).

Table 2 shows the emissions *rates* for the nine plants. Comparing the emissions rates on a per TWh basis, the Livingston gas plant has the highest emissions rate for all pollutants except for CO_2 and SO_2, which is higher from JH Campbell. Furthermore, the Karn units and JH Campbell coal plant had some of the highest emissions rates of $PM_{2.5}$ and SO_2, although the gas plants generally had higher emissions rates for NO_x and VOCs. The emissions rate metrics highlight that, from an emissions perspective, the procurement of gas plants outlined in the Consumers IRP will not necessarily offset coal co-pollutant emissions per MWh of energy produced. This could be problematic, depending on how the energy load is balanced across the gas plants when the coal plants are retired. (Bilsback Direct, 7 TR 2405).

Dr. Bilsback then used the COBRA model to analyze the total health impacts for each of the plants. (Bilsback Direct, 7 TR 2407). The COBRA model calculates the impacts of changes in emissions on $PM_{2.5}$ levels across the U.S and then uses peer-reviewed epidemiological studies and population-level health metrics to translate those changes into health impacts. (Bilsback Direct, 7 TR 2407). Each plant has a "low" and "high" estimate in COBRA, to capture the uncertainty associated with the relationship between $PM_{2.5}$ and health impacts. (Bilsback Direct, 7 TR 2407). The two values are derived from two different epidemiological studies. (Bilsback Direct, 7 TR 2407). Table 3, provided below, presents these two values as a range.

Table 3: National public health benefits of retiring power plants in 2019. Results are from COBRA using a 3% discount rate for the monetized health impacts.

Power Plant	Mortalities (cases, annual)	Mortalities (cases per TWh, annual)	Monetary Value of Total Health Impacts ($, annual)
J H Campbell[C]	36-81	4.0-9.0	$389-$879 million
Jackson Generating Station[G]	0.6-1.3	0.3-0.6	$6-14 million
Zeeland Generating Station[G]	0.2-0.5	0.05-0.12	$2-$5 million
Kalamazoo River Generating Station[G]	0.03-0.06	0.4-0.9	$0.27-$0.62 million
Livingston Generating Station[G]	0.02-0.05	1.6-3.5	$0.22-$0.50 million
New Covert Generating Project[G]	1.0-2.2	0.1-0.3	$11-$24 million
Power Plant	**Mortalities (cases, annual)**	**Mortalities (cases per MTBtu, annual)**	**Monetary Value* ($, annual)**
Dan E Karn[C, G]	3.8-8.6	0.2-0.4	$40-$92 million
Midland Cogeneration Venture[G]	2.5-5.7	0.03-0.07	$27-$62 million
Dearborn Industrial Generation[G,O]	7.5-17	0.2-0.4	$82-$184 million

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

Table 3 demonstrates that all nine plants lead to premature mortalities, respiratory and cardiovascular impacts, and a substantial financial burden associated with these impacts. All of the plants have non-fatal respiratory and cardiovascular health impacts, affecting people's lives and livelihood both near and downwind from the plant.

Dr. Bilsback uses another model, InMAP, to analyze the spatial distribution of the public health impacts of the nine power plants. InMAP is similar to COBRA in that it estimates changes in $PM_{2.5}$ emissions and then applies epidemiological data to estimate health impacts. However, the InMAP modeling is conducted at a higher spatial resolution, incorporates demographic information, and only includes mortality as a health outcome. (Bilsback Direct, 7 TR 2410). Dr. Bilsback's figures demonstrate that the largest *total* impacts from the nine power plants tended to be in the most densely populated areas that are typically downwind from each plant. (Bilsback Direct, 7 TR 2413, Figure 2). Dr. Bilsback found that the Karn units and JH Campbell coal plant have far-reaching impacts, including substantial impacts outside of Michigan, including in New York and Pennsylvania. The Midland gas plant, which Consumers purchases power from, also has substantial *total* health impacts, in part due to its proximity to populous areas. (Bilsback Direct, 7 TR 2412).

Dr. Bilsback also used InMap to present per capita health impacts across race and ethnicity. Dr. Bilsback explains that this data can demonstrate some equity dynamics of $PM_{2.5}$ exposures and related health impacts, but references Dr. Krieger's testimony explaining that these metrics will not capture all of the ways in which inequities will manifest. (Bilsback Direct, 7 TR 2414; Krieger Direct, 7 TR 2375). Dr. Bilsback summarized these findings in Table 4, which shows health impacts by race and ethnicity as a function of dollars per 100 people. The overall population is presented in the far-right column, to be referenced as a comparative data point. Table 4 is reproduced here:

Table 4: Per capita health impacts by race and ethnicity. Values given in $ per 100 people. (Note: Data are from InMAP model runs. The analysis only included mortality as a health outcome and did not include a discount rate in the economic valuation.)

Power Plant	Black	Latino	Native	Asian	White*	Overall
Dan E Karn[C,G]	2.5	2.0	1.8	2.9	4.8	3.9
J H Campbell[C]	153	58	67	97	180	150
Jackson Generating Station[G]	4.8	1.2	1.7	2.6	4.8	4
Zeeland Generating Station[G]	1.2	0.8	0.8	1.0	2.3	1.8
Midland Cogeneration Venture[G]	6.1	4.1	6.3	5.4	18	13
Kalamazoo River Generating Station[G]	0.1	0.05	0.07	0.08	0.2	0.2
Livingston Generating Station[G]	0.01	0.01	0.05	0.01	0.05	0.03
New Covert Generating Project[G]	3.4	1.4	1.8	1.9	4.2	3.5
Dearborn Industrial Generation[G,O]	57	18	9.4	14	18	23

* White, not including Latino

C: Primary fuel is coal; G: Primary fuel is pipeline natural gas; O: Primary fuel is other gas

All the plants in Table 4 except Dearborn have roughly-equal to moderately-higher per-capita health impacts for White people than the overall population. Additionally, the JH Campbell, Jackson, and Dearborn plants have higher health impacts per capita for Black people than the overall population. Dearborn has especially disproportionate impacts for Black people (2.5 times higher impacts per capita than the overall population). (Bilsback Direct, 7 TR 2415).

VI. THE COMPANY'S PROPOSAL TO RETIRE THE COAL UNITS IS SUPPORTED BY THE ENVIRONMENTAL JUSTICE ANALYSIS AND SHOULD BE APPROVED

The rapid retirement of coal plants proposed in Consumers IRP will save dozens of lives per year due to reductions in health-damaging air pollutant emissions and holds additional public health benefits such as the reduction of coal ash waste. (Krieger Direct, 7 TR 2366). Dr. Bilsback's findings in Table 3 above indicate that the combined 2019 emissions from Consumers' coal-burning power plants—J.H. Campbell and D.E. Karn—have modeled mortality impacts of 40-90 premature deaths and $429-$971 million in health impacts annually; every year of early retirement for these plants could therefore achieve a public health benefit of nearly a billion dollars through avoided health impacts. (Krieger Direct, 7 TR 2379). Campbell is particularly important to retire because it leads to greater total health impacts than any other individual plant. (Bilsback Direct, 7 TR 2396).

Dr. Bilsback and Dr. Krieger's environmental justice findings further support the Company's proposal to retire its coal units. Company witness Blumenstock testifies that the benefits of accelerated retirement outweigh continued operations at all of the coal units, with the caveat that the Company expects to recover the remaining book balances as a regulatory asset consistent with the original design lives of the units. (Blumenstock Direct, 3 TR 99).

Dr. Bilsback and Dr. Krieger's environmental justice findings supporting retirement of the coal units are generally consistent with the business and risk analysis of the coal units by other intervening parties and Staff, though Staff and ABATE do raise concerns about the retirement of Campbell 3.[1] Attorney General witness Dr. David Dismukes recommends "that the Commission approve the proposed early retirements of Karn Units 3 and 4 in May of 2023 and Campbell Units 1 through 3 in May of 2025, and the request to recover the total remaining book value at retirement, including decommissioning costs, as will be determined through future filings closer to the early retirement dates." (Dismukes Direct, 7 TR 2102:11-15). MNS witness Tyler Coming discussed and adopted the retirement savings modeled by Consumers for the Karn and Campbell units, noting that the Company had provided "myriad reasons" for retiring its coal units. (Comings Direct, 8 TR

[1] Wolverine Supply Cooperative witness Thomas King also raises concerns about the early retirement of Campbell 3, but these concerns appear to be related entirely to the Company's fulfillment of its contractual agreements with Wolverine surrounding decommissioning. (King Direct, 7 TR 2267-2268).

2957-58). Staff witness DeCooman testified that Staff found the Company's retirement analysis complied with requirements, and found retirement dates for Campbell 1 and 2 to be reasonable and supported by the model results. (DeCooman Direct, 8 TR 3458; 3466:16-22). UCC witness Cira-Reyes supports shutting down the coal fired plants because the decrease in greenhouse gas emissions and air pollution resulting from the retirement of the oil- and coal-fired plants will reduce costs associated with health care and lost productivity and avoid contributing to the health impacts of climate change. (Cira-Reyes Direct, 8 TR 2493).

Both Staff witness DeCooman and ABATE witness Andrews express concern that Consumers has failed to fully support the decision to retire Campbell 3 in 2025, and both witnesses encourage further study. Dr. Bilsback provided rebuttal testimony responding to ABATE witness Andrew's argument that Consumers had not demonstrated that retirement of Campbell 3 in 2025 was in the best interest of customers. Dr. Bilsback, who had analyzed each unit on an individual basis, provided for the Commission information on Campbell 3 in particular. Dr. Bilsback explained that Campbell 3 should be prioritized for retirement because it "has the highest total health impacts of the coal and gas plants investigated in my Direct Testimony." (Bilsback Rebuttal, 7 TR 2398). Dr. Bilsback stated:

> For every year that Campbell 3 is running at 2019 emissions levels, the plant contributes approximately 12-27 premature mortalities per year or $130-293 million in health impacts. **The impacts of Campbell 3 alone are higher than any of the other plants in Consumers' portfolio**, including Dan E Karn (3.8-8.6 annual mortalities; $40-$92 million) and Dearborn Industrial Generation (7.5-annual mortalities; $82-$184 million).

(Bilsback Rebuttal at 4:5-10, emphasis added). Moreover, Campbell 3 contributes a relatively high percentage of the total emissions from JH Campbell for $PM_{2.5}$ (67%), VOCs (62%), NO_x (41%), and CO_2 (60%). And, although Campbell 3 has lower emissions rates than the overall plant for some pollutants, Campbell 3 has the highest $PM_{2.5}$ emissions rates of any unit. (Bilsback Rebuttal, 7 TR 2397).

MNS witness Comings also rebuts ABATE witness Andrews and Staff witness DeCooman, criticizing technical elements of ABATE's and Staff's modeling and raising concerns that the additional analyses requested by those witnesses for Campbell 3 would effectively delay the decision to retire Campbell 3 until the next IRP. (Coming Direct, 8 TR 3028). Dr. Bilsback's testimony is clear that each year of delay in Campbell 3's retirement results in significant emissions and irreversible impacts on public health. Given that MNS demonstrates a lower-cost, reliable alternative portfolio that retires Campbell 3 as proposed by Consumers—even without purchase of the CMS Affiliate gas plants (Comings Rebuttal, 8 TR 3027:13-19)—the Commission should approve the early retirement of the coal units in this IRP.

VII. THE COMPANY'S PROPOSAL TO PURCHASE THE THREE AFFILIATE PLANTS IS NOT SUPPORTED BY THE ENVIRONMENTAL JUSTICE ANALYSIS

The ongoing and expanded use of natural gas in the IRP raises environmental equity and public health concerns. In particular, DIG is located in an area with high cumulative environmental health impacts and socioeconomic burdens, a dense population, and has very high pollutant emission rates and public health impacts compared to other gas plants—and even higher public health impacts than the coal-burning D.E. Karn facility. (Krieger Direct, 7 TR 2366). Dr. Bilsback finds that "the Dearborn gas plant has higher annual emissions than the Karn coal plant for all pollutant types analyzed except NO_x and CO_2. Depending on how Dearborn is operated, this plant may offset much of the emissions benefits from retiring Karn early." (Bilsback Direct, 7 TR 2405:7-10). The Company dismisses this potential for a material emissions increase resulting from the purchase of DIG by using an arbitrary "variability" metric to deem these increases immaterial. To test whether acquisitions of the gas plants would lead to an increase in emissions, the Company compared the PCA to an "alternate plan" that assumed no changes in the dispatch of the four gas plants. (Breining Cross, 6 TR 1388:4-18; 1391:3-8). Company witness Breining agreed that, when comparing the Company's plan to this alternate plan, there was an overall increase in emissions, but argued that this increase was within the range of normal annual variability. (Breining Cross, 6 TR 1400:6-16). But this analysis was flawed because it compared only a scenario where Consumers operated all four of the gas plants as they are currently dispatched and did not consider emissions on a plant-by-plant basis. (Breining Cross, 6 TR 1401:12-19). Because the Company failed to predict potential emissions changes from each of the gas plants individually, there is no way of knowing whether any individual plant contributes to increased emissions above even this arbitrary variability metric. (Breining Cross, 6 TR 1402:3-11).

Testimony from Staff and Intervenors amplifies the environmental justice and public health concerns associated with the purchase of the three affiliate gas plants. MEIBC/IEI/CGA witness Burgess explains that the competitive solicitation's Request for Proposals ("RFP") only allowed existing gas resources to participate and excluded other viable alternatives. (Burgess Direct, 8 TR 3298:1-4). Witness Burgess explains that this limitation effectively crowded out investments from other competitive technology categories—particularly storage—for the next five to ten years. (Burgess Direct, 8 TR 3301). When paired with renewable energy generation, storage is effective in reducing the public health and environmental justice concerns detailed in the testimony of Dr. Kreiger (Kreiger Direct, 7 TR 2384:13-2385:5). Even where environmental justice concerns are not present, use of storage resources can reduce high marginal emissions. For example, the Livingston Generating Station, has low total emissions but the highest rates of NO_x emissions per megawatt-hour of any plant in Consumers' portfolio. This plant is not located in an environmental justice community, but replacing a plant with high emission rates such as this one with storage will help reduce some of the highest marginal emissions on the grid, and this energy storage can provide additional services beyond meeting peak demand. (Krieger Direct, 7 TR 2385:6-21).

Staff witness Jesse Harlow also evaluated the RFP process, identifying that Staff's "primary concern is with the affiliate units." (Harlow Direct, 8 TR 3557). Staff witness Harlow found the RFP process used to solicit natural gas generation resources to be deficient, because it was so narrowly defined that it could not accurately determine a fair market price for the assets. (Harlow Direct, 8 TR 3557). Consumers consistently treated the affiliate units as a single, bundled resource, and failed to evaluate any model runs with just a subset of those three units. (Comings Direct, 8 TR 2983). MNS witness Comings states: "As a result, one can only see portfolios with or without the entire gas acquisition, which is a limited framework that prevents the exploration of individual or subsets of the plants." (Comings Direct, 8 TR 2983:13-15).

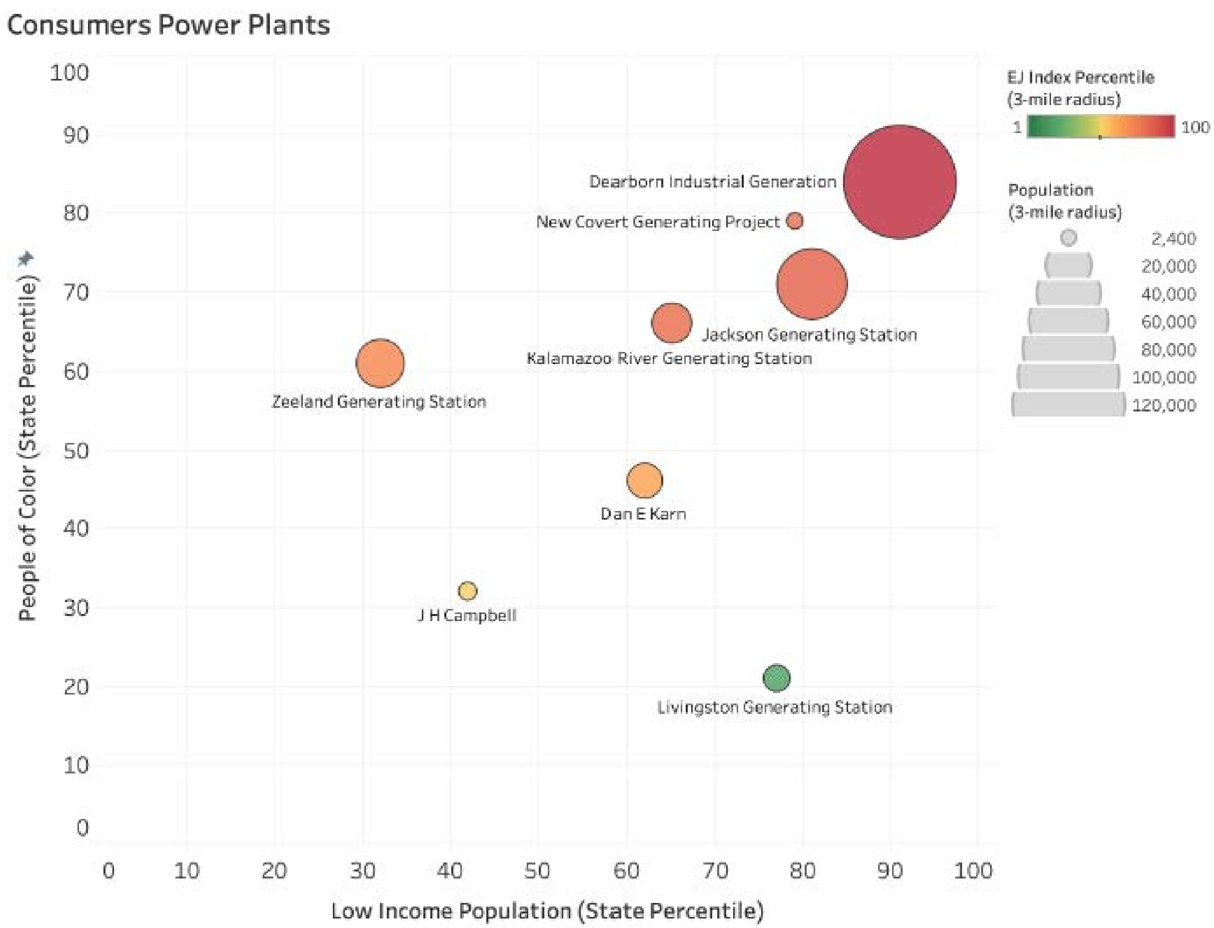
Ms. Waske Sutter from the City of Grand Rapids emphasized in her testimony that natural gas plants are still fossil fuel-based electricity generation. While she is glad that the Company does not seek to build new fossil fuel infrastructure, the gas units are not zero-emissions resources. (Waske Sutter Direct, 7 TR 2354). It is important to Grand Rapids and its residents that Consumers generate all of its energy from renewable resources as quickly as possible. The more energy Consumers generates from renewable resources, the closer the city gets to its renewable energy goals and the greater health and environmental benefits it achieves. (Waske Sutter Direct, 7 TR 2354). The Grand Rapids City Commission recently passed a resolution declaring climate change a crisis, and some of the city's residents—including the Grand Rapids Climate Coalition—have demanded that the city commit to achieving community-wide carbon-neutrality for all of Grand Rapids by 2030. Consumers' acquisition of the three affiliate units will make it even harder for

Grand Rapids and its residents to meet either the community's call for a 2030 goal or the city's established municipal carbon goals.

VIII. DIG IS ESPECIALLY PROBLEMATIC FROM AN EJ PERSPECTIVE

A. DIG performs very poorly in the Environmental Justice analysis.

Consumers' proposed purchase of DIG is particularly harmful because, among the four proposed gas plants, DIG is responsible for most of the mortalities identified by Dr. Bilsback (7.5-17 premature mortalities per year) and leads to per capita health impacts that are 2.5 times higher for Black people than the overall population. (Bilsback Direct, 7 TR 2397). DIG has the largest nearby population (118,000 people in a three-mile radius) and the highest cumulative EJ Index score (99th percentile). Dr. Krieger created a visual analysis that represented population through the size of circles (larger circles have larger population) and an EJ Index score through color of the circles (red is a higher EJ index score, and green is lower). DIG's poor performance in this analysis stands out:



These data highlight the significant equity concerns associated with this proposed purchase. While DIG is already operating, Consumers' proposed purchase of the plant ensures ongoing operation and financial support of a facility whose shutdown would benefit public health and reduce impacts on an overburdened community. (Krieger Direct, 7 TR 2382). The purchase also transfers the responsibility for the environmental harm and future liabilities from CMS shareholders to ratepayers

Ms. Waske Sutter from the City of Grand Rapids also expresses particular concern about Consumers' purchase of DIG. Ms. Waske Sutter was appointed to serve on the inaugural Michigan Advisory Council on Environmental Justice (MAC-EJ), and the AK Steel plant where DIG is located has been a topic of much concern among the MAC-EJ. Ms. Waske Sutter reviewed the EGLE Advisory Opinion, and found no indication that AK Steel, Consumers, or EGLE have evaluated the local community impacts of air pollution from DIG, or how the cumulative impacts of those emissions may harm the community. Even if neither Consumers nor EGLE are obligated to undertake such a review, Ms. Waske Sutter testifies that it is critical for the cumulative impacts to be analyzed as well as other environmental justice concerns. Cumulative impacts are taking on increasing importance in environmental analysis at a state and federal level.[2]

B. Purchasing DIG may increase emissions.

CEOs witness Dr. Bilsback raises concerns that purchasing DIG may actually offset the benefits of retiring Karn, because DIG has higher emissions than the Karn units for all pollutant types analyzed except NO_x and CO_2. (Bilsback Direct, 7 TR 2405:4-10). While Company witness Breining claims that purchase of the four gas plants does not increase emissions beyond expected annual variability, she cannot claim this is true for DIG specifically, because the Company did not conduct a plant-by-plant analysis. (Breining Cross, 6 TR 1402:3-11).

DIG has the highest total health impacts of the four proposed gas plants (7.5-17 mortalities per year) and has cases per-MMBtu similar to the coal-burning Karn plant. This is due in part to the disproportionately high levels of primary and secondary precursor pollutants—such as SO_2—being emitted from DIG and its proximity to high-density populations. Purchasing DIG to offset coal power in the near term could potentially counteract some of the benefits of retiring the Karn and JH Campbell plants early. Dr. Bilsback explains that there are several ways a gas plant can have as much or more air pollutant emissions than a coal plant. If a fuel other than natural gas is used at the facility, this could increase either total emissions and/or emissions rates. (Bilsback

[2] *See, e.g.,* Kiana Courtney, *#DenyThePermit? A Call for Cumulative Impacts Legislation by Frontline Communities,* Natural Resources & Environment, Vol. 36, No. 2, Fall 2021.

Direct, 7 TR 2406). That is likely the case with DIG, which uses waste gas from a steel plant in a blast furnace to produce steam in addition to pipeline natural gas. (Bilsback Direct, 7 TR 2406). Dr. Bilsback explains that the blast furnace waste gas produces much higher emissions of $PM_{2.5}$ and SO_2 than the other pipeline natural gas units, and that the chemical nature of the fuel and the conditions under which it is combusted can lead to changes in total emissions or emissions rates. (Bilsback Direct, 7 TR 2406).

Even though some of the fuel consumed at DIG is used to co-produce steam in addition to electricity, purchasing the electricity produced at the plant will support its ongoing operation—and ongoing health impacts. And while Consumers argues that the beneficial reuse of blast furnace gas should be taken into account when evaluating DIG, its analysis of beneficial reuse is at best incomplete. The Company did not consider a single alternative use for the blast furnace gas. (Breining Cross, 6 TR 1428-29). In addition, DIG carries significant uncertainties which leave any owner of the plant vulnerable to potential environmental regulations. (Comings Direct, 8 TR 2993:11-12). Consumers' purchase of DIG shifts the risks of regulatory enforcement activities and reduction of pollution in already overburdened communities from CMS shareholders to Consumers' ratepayers.

IX. THE COMMISSION SHOULD DENY CONSUMERS' REQUEST FOR REGULATORY ASSET TREATMENT OF ITS RETIRING COAL UNITS IN THIS CASE

Allowing Consumers to recover the net unrecovered book balance will unfairly and unnecessarily increase the cost burden on the Company's most burdened customers. Staff and multiple intervening parties submitted testimony demonstrating that a decision on regulatory asset treatment of the retiring coal units is not necessary in this proceeding, and that Consumers' proposal to treat net unrecovered book balance as a regulatory asset is costly for customers.

Attorney General Witness Dismukes recommends that recovery of remaining book value be considered in a future proceeding, and that the Commission direct the Company to provide a proposal in that proceeding for low-cost debt financing rather than continued recovery through traditional ratemaking. (Dismukes Direct, 7 TR 2080:1-10). MNS witness Douglas Jester proposes that the Commission direct Consumers to file a securitization request not later than March 1, 2023, for the expected remaining net book value of such plants as the Commission approves to retire. (Jester Direct, 7 TR 2610:6-8). ABATE witness Walters testified that securitization financing would result in a lower Net Present Value for the PCA, and also noted that there are a number of other alternatives to securitization that the Company failed to consider. (Walters Direct, 7 TR 2860-2861).

Dr. Dismukes recommendation that the Company hire a securitization consultant to negotiate on behalf of ratepayers is consistent with concerns raised by CEOs witness Boris Lukanov, who testified regarding energy burden. (Dismukes Direct, 7 TR 2103). Approving regulatory asset treatment in this case will unfairly and unnecessarily increase the energy burden on Consumers customers. The Commission should reject Consumers request for regulatory asset treatment in this case and require the Company to proceed as recommended by Dr. Dismukes by determining Consumers' recovery of the total remaining book value through future filings closer to the retirement dates of the coal units. (Dismukes Direct, 7 TR 2080:1-10). The CEOs also support direction from the Commission regarding low-cost debt financing and, if securitization is used, the hiring of a securitization consultant to represent customers. (Dismukes Direct, 7 TR 2080:1-10, 2103).

X. THE COMMISSION SHOULD DIRECT THE COMPANY TO STUDY/MODEL BEHIND THE METER DISTRIBUTED GENERATION

In its Interim Order on the DTE IRP in Docket No. U-20471, the Commission responded to critiques from intervening parties that DTE had insufficiently considered distributed generation. The Interim Order stated:

> The Commission finds that a DG analysis is imperative for IRPs. The Commission finds that the pace of changes in technology and customer behavior in this area demands that DTE Electric not screen out DG in its next IRP filing. The company's rationale that DG resources are not dispatchable or schedulable is unconvincing, as the same could be said for other elements of a modern electric grid. Similarly, its arguments over cost seem to ignore the investments customers have made in these systems, and focuses only on utility-owned DG resources. The Commission directs the company to fully analyze the effects of DG on the company's plan in its next IRP filing.

(Docket No. U-20471, February 20, 2020 Order at 62).

In this IRP, Consumers considered, but did not model, distributed generation as a resource. (Kenworthy Direct, 7 TR 2314). In an effort to address distributed generation, Consumers included two different types of solar in its modeling: distribution-connected solar and transmission-connected solar. (Kenworthy Direct, 7 TR 2314). "Distribution-connected solar" refers to front-of-the-meter, small wholesale generators, similar to the 584 MW of projects from the PURPA QFs that were accepted in the settlement agreement in Case No. U-20165. (Kenworthy Direct at 9). Transmission-connected solar are projects such as the utility scale projects the Company is currently developing under its last IRP. In the Company's plan, "distributed generation" refers to behind-the-meter-generation ("BTMG"), which appears to include generators currently eligible to participate in the Company's DG Tariff. (Kenworthy Direct, 7 TR 2315).

In light of the findings of the modeling exercise directed by CEOs witness Kenworthy, and described in more detail below, there are sufficient grounds for the Commission to direct Consumers to modify its IRP to: (1) initiate a pilot program to test the Distributed Generation adoption model proposed here; and (2) conduct benefit-cost analysis in the study to serve as a basis for a fully realized Distributed Generation Resource model in future IRPs. (Kenworthy Direct, 7 TR 2332).

A. The Company's approach to evaluating distribution-connected solar is flawed.

The Company's approach to evaluating distribution-connected solar is flawed, because (1) it compared incomparable resources, (2) it screened out BTMG without allowing the model to choose it, and (3) it uses improper cost assumptions for utility-scale solar.

First, for modeling the distribution connected solar resource, the Company compared the price of a utility scale solar PPA to a PPA for a much smaller wind project. (Kenworthy Direct, 7 TR 2316). The Company's use of a different technology and scale is inexplicable, given that the Company has actual cost data from fifteen comparably sized PURPA QF projects from its September 30, 2019 solicitation. (Kenworthy Direct, 7 TR 2316). In the future, the Company should use data from competitive solicitations to inform cost assumptions for comparably sized solar projects. (Kenworthy Direct, 7 TR 2316).

Despite the flawed comparison, the Company concludes that the price competitiveness between transmission- and distribution- connected solar is relatively narrow and that it is possible that distribution-connected resources may be a lower-cost option than transmission-connected resources. (Kenworthy Direct, 7 TR 2317). Yet even though the Company's PCA does include incremental capacity additions, it does not distinguish between transmission- or distribution-connected solar since both are eligible to compete in the competitive selection process. (Kenworthy Direct, 7 TR 2317). There are benefits to being connected at the distribution level, such as avoided network transmission upgrades costs, but the Company does not factor those benefits into the modeling. Distinguishing between transmission and distribution connected resources, and reflecting the benefits of distribution-connected resources in the price offered the model, will ensure that the model has an opportunity to choose the resources most beneficial for ratepayers. In future IRPs the Company should include distribution connected solar as a separate resource, taking into account the full spectrum of potential distribution system benefits. Specifically, the Commission should direct the Company to continue to improve the evaluation of distribution system benefits in considering resources offered to IRP modeling. (Kenworthy Direct, 7 TR 2314).

The Company made a second, and more significant mistake, when it removed distributed generation at the screening level prior to modeling. (Kenworthy Direct, 7 TR 2317). BTMG should not have been screened out, and doing so was detrimental to customers. The Company did not explain why distributed generation was screened out, but did indicate that it would "continue to monitor and understand trends and adoption rates of distributed generation resources in future planning processes." (Exhibit A-2 at 138). Customer-sited BTMG was included as a separate supply side resource in the Advanced Technology Scenario in the modeling to compare costs in the sensitivities with and without BTMG, but the Company did not allow the model to select BTMG as a resource. (Walz Direct, 3 TR 316:37-38) The Company also continued the conventional practice of treating BTMG as a reduction in load in the load forecast rather than as a supply-side resource. The result of this modeling was that in the Advanced Technology scenario, BTMG merely displaced utility scale solar, some of which may have been distribution connected, rather than being chosen alongside, or competing fairly with, distribution- and transmission-connected solar.

This treatment of distributed solar in the Advanced Technology scenario inappropriately forces the model to select distributed solar, rather than allowing the model to optimize the future system with customer-sited solar as a resource. While the Company made several improvements in its modeling of different types of distribution-connected solar resources, its modeling of BTMG did not consider the benefits of distribution connected solar, including BTMG. (Kenworthy Direct, 7 TR 2321). By not including distributed generation as a selectable resource, the Company may have missed an important opportunity to cost effectively to meet its capacity needs. This is especially important because distribution-connected solar resources are likely to decrease costs for customers. Depending on where resources are deployed and how they are operated, the expansion of utility-scale and distributed energy storage in the IRP holds multiple potential benefits, including replacing high emission rate peaker power plants, such as Livingston, and increasing energy resilience, particularly for vulnerable populations. (Krieger Direct, 7 TR 2367; Kenworthy Direct, 7 TR 2325).

Leveraging distribution-connected solar resources provides multiple benefits beyond the costs and benefits recognized in traditional resource planning and may in fact result in lower total system costs for all customers. CEOs witness Kenworthy cites to a recent study by Vibrant Clean Energy ("VCE") for the Local Solar for All Coalition, which found that deploying significant amounts of local clean energy is the most cost-effective way for the United States to transition to a clean energy system by 2050, while saving consumers up to $473 billion on electricity. VCE's research also shows that leveraging the precision and flexibility of local clean energy can reduce overall system costs and, therefore, costs to all customers. Co-optimization of distribution-connected resources with utility scale investments provides even greater benefits in the form of reduced cumulative costs. Distributed generation also provides benefits in the form of capacity avoidance/deferral, ancillary services, line loss reduction, and resilience. (Kenworthy Direct, 7 TR 2323).

Finally, in its modeling, the Company improperly used national cost-assumptions for utility-scale solar resources, rather than using results from its most recent competitive solicitation process. Although contracts were not finalized until January 2021, the Company's Independent Administrator, ENEL X, had provided in spring of 2020 aggregate bid information sufficient to inform the cost estimate for modeling the transmission-connected, utility scale solar resources. (Kenworthy Direct, 7 TR 2316).

B. The Commission should require Consumers to model distributed generation as a resource.

Consumers should model distribution-connected solar in a more useful way, because it is clear that customers will continue to develop distribution-connected solar to meet various customer needs, from reliability to land use to more aggressive decarbonization of the electric grid. For example, the City of Grand Rapids has been working for over seven years to find a successful pathway to install solar at the Butterworth Landfill. Ms. Waske Sutter from the City of Grand Rapids explains that:

> Butterworth is a great example of how renewable energy can lead to the beneficial reuse of urban brownfield sites. The site is located in the city limits, very close to the load and within the community that it could serve. The land could be used for passive recreation, but is more valuable deployed for solar and is in a location visible to the community. While the costs of developing solar on this brownfield site may be higher than using a greenfield, I believe that the intangible benefits gained from using this parcel outweigh those additional costs.

(Waske Sutter Direct, 7 TR 2351). Butterworth is not the only brownfield well-situated for distribution-connected solar. As Dr. Elena Krieger explains, there are numerous brownfields across Michigan that hold potential for remediation as solar or solar-plus-storage sites. (Krieger Direct, 7 TR 2388). "According to the EPA's RE-Powering Dataset, Michigan has 2,867 brownfield sites with as much as 14.4 GW of solar potential. NREL estimates that Michigan has 34 GW of total urban utility-scale solar potential." (Krieger Direct, 7 TR 2388).

Ms. Waske Sutter goes on to explain the many other ways in which Consumers could, in its IRP, consider opportunities for customers to install BTMG as a resource. Ms. Waske Sutter describes opportunities for BTMG development at urban brownfields near load, as well as large industrial, manufacturing, and retail rooftops available within the Grand Rapids city limits. Ms. Waske Sutter points out that supporting and siting distribution-connected solar within the city limits decreases the distance between generation and consumption, which has many tangible benefits. (Waske Sutter Direct, 7 TR 2351). The program proposed by the Company in its rebuttal testimony by witness Blumenstock may be a good starting point for discussion, and the CEOs supports the near-term deployment of battery storage resources. However, the CEOs agree with MEIBC/IEI/CGA that the Company should follow the Commission's competitive procurement guidelines and that the Commission should be cautious with respect to utility ownership of behind the meter storage. (Sherman Surrebuttal, 8 TR 3275 *et seq*).

Consumers overarching failure is that it treats distributed energy resources as an exogenous variable to their capacity expansion modeling. Like weather, or the economy, Consumers treats the growth of distributed energy resources as something that "happens to" it and needs to be planned around, rather than something that the utility can affect through its own actions. (Kenworthy Direct, 7 TR 2327). Consumers does not treat distributed energy resources as a resource that can be used to meet its customers' requirements.

CEOs witness Kenworthy proposes a Distributed Generation as a Resource ("DGR") model that relies on the robust relationship between the net present value ("NPV") cost per kilowatt for a customer to install solar and the likelihood of adoption. In the DGR model, the "cost" of distributed generation is the amount of a customer incentive that would produce a given amount of distributed solar generation. Mr. Kenworthy explains the various assumptions used to develop the inputs to the model, citing to a peer-reviewed paper published in "Renewable Energy." (Kenworthy Direct, 7 TR 2327-2328, citing Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg., *Empirical development of parsimonious model/or international diffusion of residential sola*r, 150 Renewable Energy 570, 570- 577 (2020)).

Mr. Kenworthy's proposal was modeled by CEOs Witness Chelsea Hotaling, who offered a $40/MWh level to the model. The $40/MWh incentive reflects the full cost of the incremental solar additions to the utility. The full costs of BTMG solar are not relevant since they are investments made by the customer which have no impact on the utility's costs which are the subject of the IRP. Over the term of the study period, the net present value of revenue requirements for the portfolio that included both the DG as a Resource and the Low-Income DG as a Resource model, discussed in the next section, was $12.5 million lower than the portfolio in Consumers' preferred course of action. This demonstrates that it would be cost effective from a resource planning perspective for the Company to encourage the adoption of distributed generation by its customers. (Kenworthy Direct, 7 TR 2332).

C. The Commission should initiate a "Low-Income DG as a Resource" pilot program.

The Commission should direct the Company to initiate a Low-Income DG as a Resource pilot program. (Kenworthy Direct, 7 TR 2310). Distributed generation allows energy users to own and control the long-term revenue from future energy sources, allowing individuals and families to share in wealth that historically has been limited to utility investors (for utility-owned assets) and Wall Street (for energy assets operating under Power Purchase Agreements with utilities). This opportunity can be expanded through community solar and other forms of shared renewables that allow renters and low-income households and businesses who otherwise lack sufficient capital or physical space to share in the returns from renewable generation. (Kenworthy Direct, 7 TR 2325).

Distributed rooftop solar can provide bill stability and electricity cost savings in addition to other benefits. As Dr. Lukanov explains, rooftop solar has historically been disproportionately adopted by higher income households due to high upfront costs and other barriers to entry. Consequently, the low-income, renter, and other cost-burdened households who could most benefit have historically not been able to reap the bill stability and cost reduction benefits enjoyed by higher-income, solar-adopting households. Increasing rooftop solar adoption among low-income households, including options such as community solar, could therefore prove a high-yield target for decreasing bill burdens. (Lukanov Direct, 7 TR 2448).

Job creation and local business development opportunities are inherently greater for community-based renewable energy than for large, centralized energy systems because a larger number of smaller projects creates a more stable and sustainable long-term workforce opportunity, and dispersed projects make jobs and financing more accessible to a wider range of Michiganders. (Kenworthy Direct, 7 TR 2326); *see also* MCL 460.6t(8(b) (directing the Commission to determine that, "[t]o the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state").

Distributed generation presents several opportunities for addressing equity concerns. To illustrate this, at Mr. Kenworthy's direction, witness Hotaling modeled a low-income solar incentive that as its initial cost would essentially pay the full cost of installing DG on low-income single-family homes. Ms. Hotaling modeled a $10,000,000/year program for 10 years. In each year, Mr. Kenworthy directed her to assume that the program would build as much solar at the full NREL ATB rate for residential distributed solar as it could for that amount. Witness Kenworthy explains that the model assumes an incentive design that would essentially rebate 100% of the installed costs of a system to a low-income homeowner upon energization. (Kenworthy Direct, 7 TR 2331-2332).

The low-income distributed generation program Mr. Kenworthy proposes would address equity issues. As weather extremes become more common due to climate change, rooftop solar paired with battery storage may be valuable for conferring additional resilience. This approach may be particularly impactful for groups that could benefit from bill stability for economic reasons as well as benefiting from enhanced resilience for demographic and health reasons. For example, low-income seniors may struggle to pay their bills and may be particularly vulnerable to weather extremes. Solar with battery storage may be particularly useful for them and other similarly climate vulnerable and economically-disadvantaged groups. A targeted program to evaluate and support low-income solar adoption can help provide benefits to households who could most benefit. (Lukanov Direct, 7 TR 2449).

The rebuttal testimony of UCC witness Sergio Cira-Reyes improves upon Mr. Kenworthy's proposal by proposing that the program be structured not as a rebate, but as an up-front grant. (Cira-Reyes Rebuttal, 7 TR 2539:1-7). Mr. Cira-Reyes correctly points out that rooftop solar installations "can run into the thousands, a cost that can be prohibitive for residents who do not have sufficient access to cash or credit, even if the program reimburses them later." (Cira-Reyes Rebuttal, 7 TR 2539:1-7). The CEOs agree with Mr. Cira-Reyes that the Commission should also support legitimate community solar programs and work closely with community members when developing programs, "to ensure that communities of color and low-income communities are aware of their potential benefits and can receive assistance to enroll." (Cira-Reyes Rebuttal, 7 TR 2539:9 – 2540:11).

XI. THE COMMISSION SHOULD DIRECT THE COMPANY TO IMPROVE THE EVALLUATION OF DISTRIBUTION SYSTEM BENEFITS.

The Company's modeling represents a new effort to incorporate benefits in the distribution system that can be realized through resources offered to the resource plan, but it can still be improved. (Kenworthy Direct, 7 TR 2313). For example, Company witness Nathan J. Washburn explains the development of the Battery Energy Storage System ("BESS") prototypes in the IRP modeling. In order to evaluate different use cases for the energy storage, the Company developed four different resource prototypes that were modeled to show how the technology could capture different value streams. In order to build these use cases into Aurora, the value of each of the cases were calculated outside of Aurora and provided for each prototype as a credit that reduced the cost of the asset in Aurora. While the approach described by Mr. Washburn is simple, future load changes from increased beneficial electrification as well as load profile changes from increased adoption of distributed energy resources are likely to accelerate.

A more sophisticated and granular approach to load forecasting would provide a more meaningful analysis. In comments submitted by several environmental groups on the Company's Draft Electric Distribution Infrastructure Investment Plan in June, the CEOs and other groups suggested that the Company should consider soliciting bids from third parties for Non-Wires Solutions. While this suggestion applies generally to all resource procurement solutions, it is particularly salient here as utilities have operationalized this approach in other states. For example, PGE has solicited a Request for Offers in its Distribution Investment Deferral Framework.

The Company's modeling of the storage prototypes represents an advancement in the efforts to integrate resource, transmission, and distribution system planning. The Commission should direct the Company to continue to improve the evaluation of distribution system benefits in considering resources offered to IRP modeling. In addition, the Company should include market solicitations for deferral opportunities to make sure that it can take advantage of DERs to address discrete system costs. (Kenworthy Direct, 7 TR 2314).

XII. THE COMMISSION SHOULD DENY THE FCM REQUESTED BY CONSUMERS AND ALLOW THE COMPANY TO REFILE WITH AN APPROPRIATE FCM REFLECTING A MECHANISM THAT DEMONSTRABLY RESULTS IN SAVINGS FOR CUSTOMERS.

The Commission should reject Consumers' request for an FCM as proposed because the Company fails to demonstrate that it reduces costs for Michigan customers. In its Order approving the settlement of the Company's last IRP, the Commission found persuasive ELPC and Staff's point that "the FCM is subject to Commission review in 2021 and that, if Consumers cannot show that the FCM reduces costs for Michigan customers, the Commission has the authority to discontinue the FCM for new contracts in Consumers' next IRP case." (Dkt. No. U-20165, June 7, 2019 Order at 85). Consumers has made no showing that the previously-approved FCM has benefitted customers, or that the FCM the Company seeks here will benefit customers. The Commission should deny the Company's request for an FCM, but ask the Company to revise its IRP and refile with an FCM that does demonstrate such savings.

Consumers witness Maddipatti lays out the Company's justification for an FCM, arguing that PPAs have characteristics similar to long-term debt, and that financial analysts will treat PPAs as imputed debt. (Maddipati Direct, 5 TR 946:3-7). Mr. Maddipati argues that—regardless of how the Company carries this in its capital structure—credit agencies perceive PPAs as changing the Company's debt to equity ratio, which impacts cost of capital. (Maddipati Direct, 5 TR 946:3-14). Mr. Maddipati's believes an FCM should be calculated based on imputed debt impacts, but in recognition of historic, widespread opposition to that approach, proposes instead an FCM "that is simply equal to the product of: (1) the annual PPA payment; and (2) the Company's pre-tax WACC based on its permanent capital structure (currently 8.64%)." (Maddipati Direct, 5 TR 966:13-15).

That pre-tax WACC is higher than the 5.88% approved in the settlement agreement for Consumers last IRP. (Maddipati Direct, 5 TR 945:22-946:2). Mr. Maddipati holds to his conviction that imputed debt is the driver for an FCM by deeming his proposed FCM a "reasonable proxy" for the approach. (Maddipati Direct, 5 TR 966). Mr. Maddipati encourages adoption of this FCM in conjunction with changes proposed by Company witness Troyer, who proposes removal of the cap on the FCM established by the U-20165 settlement and application of the FCM to resources in the Company's Renewable Energy Plan. (Troyer Direct, 4 TR 735).

The Commission has the authority to approve a FCM under Section 6t(15), which states as follows:

> For power purchase agreements that a utility enters into after the effective date of the amendatory act that added this section with an entity that is not affiliated with that utility, the commission shall consider and may authorize a financial incentive for that utility that does not exceed the utility's weighted average cost of capital. MCL 460.6t(15).

The Commission has recently had occasion to consider, and reject, a proposed FCM in the DTE Voluntary Green Pricing Case. (Dkt. U-20713 *et al.*, June 9, 2021 Order). Like the FCM proposed by Consumers here, DTE proposed a structure that would allow the company to earn an FCM on a given PPA equal to the sum of the PPA payments in that year multiplied by an incentive factor equal to some measurement of WACC. (June 9, 2021 Order at 8). The Commission rejected this approach. (Dkt. U-20713 *et al*. at 27). The Commission noted that "[t]he primary intent of Section 6t(15) is to incentivize electric providers to utilize PPAs that may be more cost-effective over self-build options that have the benefit of earning the company a rate of return." (Dkt. U-20713, June 9, 2021 Order at 23). Consumers use of WACC could, as the Commission recognized it might for DTE, lead to the perverse result of higher costs for customers than self-build options. Indeed, the very purpose of creating an incentive for Consumers to enter into PPAs is that they have often been less costly on a levelized basis than company-owned projects. (*See* Dkt. U-20713, June 9, 2021 Order at 23).

Mr. Maddipati rejects this shared savings mechanism on the basis that it fails to incorporate the credit impacts on the cost of capital. (Maddipati Rebuttal, 5 TR 970:11). Whether it incorporates these credit impacts is of no import, because Consumers has failed to demonstrate that they exist. The most Mr. Maddipati can do is speculate—from his perspective as treasurer for the Company—that a change in the equity to debt ratio would result in a downgrade of the Company. (Maddipati Cross, 5 TR 1069:20-1070:7). Mr. Maddipati points to no specific example where a downgrade occurred because the Company entered into PPAs.

The intent of an FCM is to ensure that the resources ultimately selected were truly in the best interest of Consumers' customers. The FCM is not a mechanism for compensating the Company for perceived financial impacts of PPAs. Consumers incentive should be to the savings achieved for customers through a PPA option. In this way, the utility's compensation for entering into the PPA is directly tied to the benefit customers receive. The Commission should reject Consumers' proposal for an FCM with an allowance for the Company to submit IRP revisions under MCL 460.6t(7) with a financial incentive based on savings achieved for customers similar to that approved in Docket No. U-20713 *et al*. (*see* June 9, 2021 Order at 27-28, illustrating how such a financial mechanism could operate).

XIII. THE COMMISSION SHOULD ORDER THE COMPANY TO SET THE MUST-RUN DESIGNATION TO "OFF."

CEOs witness Daniel recommends that "the Commission should order the Company to set the must-run designation to 'off' as the default setting for all thermal coal units in all scenarios and sensitivities in its next IRP." (Daniel Direct, 7 TR 2298:9-11). Mr. Daniel details the other options the company has versus setting units as must run, as well as the changing market dynamics that support the need for a change in operations of the coal-fired power plants.

Consumers attempts to justify application of the must-run constraint on thermal power plants, arguing that it has concerns about the physical limitations of the power plants and pointing out that the units are offered into the MISO market as must run. (Munie Direct, 7 TR 1928). While the Company does remove the must-run designation for the carbon price scenario—because of the impact a carbon price will have on coal plant economics—Mr. Daniel points out that there are many factors modeled in an IRP that will impact coal plant economics yet the company retains the must-run designation for those other scenarios. The Company doesn't refute any of witness Daniel's testimony as to why the must-run designation should be removed in these other scenarios.

In rebuttal testimony, witness Munie further argues that—because these coal plants are retiring in the near future—changing the must-run designation has "no relevance," stating that "it is no longer necessary to conduct model runs in future IRPs with the must-run designation set to off because these units will be retiring within a year or less of the beginning of the study period." (Munie Rebuttal, 7 TR 1945). Witness Munie does not dispute witness Daniel's arguments about why changing market dynamics merit a change in how the company models the coal units, asserting only that "[the] Commission has repeatedly rejected recommendations to model coal units as must-run resources in previous regulatory cases." (Munie Rebuttal, 7 TR 1945). However, as pointed out in direct testimony by Mr. Daniel, market prices and dynamics have changed rapidly over the past ten years, prompting many utilities to change how they operate coal plants. The Commission recently recognized this changing dynamic in its order in PSCR Docket No. U-20804, where it warned Indiana Michigan Power Company about possible above market costs associated with committing coal plants as must run. (November 18, 2021, Order at 25). While the

Commission might have allowed the use of the must-run designation in the past, the Company should not be allowed to hide behind rulings that are no longer relevant due to rapidly changing market dynamics of the energy transition.

Lastly, the Company argues that the CEOs' recommendation for the Commission to set an expectation that all utilities remove the must-run designation in future IRPs should not be considered because "one utility's IRP is not the arena in which the Commission should make a final decision or adopt new requirements." (Munie Rebuttal, 7 TR 1946:4-5). This argument mischaracterizes the CEO's request. The CEO's recommendation is clearly applicable to the Company in its future IRPs. The CEOs cannot forecast what resources will ultimately be retired as a result of this IRP, nor can they discern whether the Company will seek in the future to model coal units. To the extent the Commission's decision in this case may be used in the future as precedent for other utility IRPs, certainly the Commission does not avoid making decisions that apply to one utility simply because they may impact other utilities in future cases. Furthermore, the issues here are similar across utilities, and it would be appropriate for the Commission to set forth its expectations in this case to help guide future IRPs.

XIV. CONCLUSION

Testimony from the CEOs witnesses demonstrates that there are still significant opportunities to improve the Company's Environmental Justice ("EJ") assessment to include more quantitative analysis. The CEOs' expert witnesses described sound methodology for performing an EJ analysis of each plant in the Consumers PCA, quantifying emissions, health impacts, and assessing the demographics of impacted areas.

Informed by the CEOs EJ analysis and other expert testimony, the MPSC should approve portions of the Company's application, but recommend the following revisions under MCL 460.6t(7):

- The Company should adopt the CEOs EJ Analysis;
- The Company should not acquire the three affiliate gas plants;
- The Company should file a securitization case to recover the net remaining book; balance of the retired coal plants; and
- The Company should revise the FCM to reflect shared savings that benefit customers.

The MPSC should also recommend that in the Company's next IRP:

- The Company more effectively incorporate distribution planning with resource planning, consistent with the CEOs' recommendations;
- The Company model distributed generation ("DG") as a resource, including a pilot program for low-income DG; and
- The Company turn off the must-run indicator for coal units in all runs.

Respectfully submitted,

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Margrethe Kearney
Environmental Law & Policy Center
146 Monroe Ctr. St. NW Ste 422
Grand Rapids, MI 49503
T: (773) 726-8701
F: (312) 795-3730
mkearney@elpc.org

Dated: January 4, 2022

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of **CONSUMERS ENERGY COMPANY** for Approval of an Integrated Resource Plan under MCL 460.6t, certain accounting approvals, and for other relief.	))))))	Case No. U-21090

PROOF OF SERVICE

I hereby certify that a true copy of the foregoing *Opening Brief of The Environmental Law & Policy Center, Ecology Center, The Union of Concerned Scientists and Vote Solar* was served by electronic mail upon the following Parties of Record, this 4th of January, 2022.

Consumers Energy Anne M. Uitvlugt Bret A. Totoraitis Gary A. Gensch Jr. Ian F. Burgess Michael C. Rampe Robert W. Beach Theresa A.G. Staley	 anne.uitvlugt@cmsenergy.com bret.totoraitis@cmsenergy.com gary.genschjr@cmsenergy.com ian.burgess@cmsenergy.com michael.rampe@cmsenergy.com robert.beach@cmsenergy.com theresa.staley@cmsenergy.com
MOAHR Sally Wallace Meaghan Dobie	 wallaces2@michigan.gov dobieM@michigan.gov
Staff Meaghan Kolioupoulos Spencer Sattler Amit Singh Nicholas Q. Taylor	 KolioupoulosM@michigan.gov sattlers@michigan.gov singha9@michigan.gov taylorn10@michigan.gov
Attorney General Celeste R. Gill Amanda Churchill	 Gillc1@michigan.gov Churchilla1@michigan.gov AG-ENRA-Spec-Lit@michigan.gov
ELPC et al. Margrethe Kearney Heather Vogel	 mkearney@elpc.org hvogel@elpc.org

Hemlock Semiconductor Jennifer Utter Heston A. Louise Johnson	 jheston@fraserlawfirm.com ljohnson@fraserlawfirm.com
BMPs Tom Waters	 twaters@fraserlawfirm.com
MEC/NRDC/SC Christopher M. Bzdok Lydia Barbash-Riley Michael C. Soules Karla Gerds Kimberly Flynn Breanna Thomas Jill Smigielski	 chris@envlaw.com lydia@envlaw.com msoules@earthjustice.org
GLREA/RCG Don Keskey Brian Coyer	 donkeskey@publiclawresourcecenter.com bwcoyer@publiclawresourcecenter.com
ABATE Stephen A. Campbell Michael J. Pattwell James Fleming	 scampbell@clarkhill.com mpattwell@clarkhill.com jfleming@ClarkHill.com
Mackinac Center for Public Policy Jason Hayes Derk Wilcox	 hayes@mackinac.org wilcox@mackinac.org
Energy Michigan/EIBC/IEI/ Clean Grid Alliance Timothy J. Lundgren Laura A. Chappelle Justin Ooms	 tlundgren@potomaclaw.com lchappelle@potomaclaw.com jooms@potomaclawgroup.com
METC Richard J. Aaron Lisa M. Agrimonti Olivia R.C.A. Flower Amy Monopoli	 RAaron@dykema.com lagrimonti@fredlaw.com oflower@dykema.com amonopoli@itctransco.com
Wolverine Power Supply Cooperative, Inc. Jason T. Hanselman Joseph J. Baumann Lauren E. Fitzsimons	 JHanselman@dykema.com jbaumann@wpsci.com LFitzsimons@dykema.com

Michigan Public Power Agency Peter H. Ellsworth Nolan J. Moody	 pellsworth@dickinsonwright.com nmoody@dickinsonwright.com
Citizens Utility Board Abigail Hawley Karla Gerds Kimberly Flynn Breanna Thomas Jill Smigielski	 abbie@envlaw.com karla@envlaw.com kimberly@envlaw.com breanna@envlaw.com jill@envlaw.com
Urban Core Collective Nicholas Leonard Andrew Bashi Mark Templeton Robert Weinstock	 nicholas.leonard@glelc.org andrew.bashi@glelc.org templeton@uchicago.edu rweinstock@uchicago.edu sgewirth@uchicago.edu aelc_mpsc@lawclinic.uchicago.edu
Cadillac Renewable Energy LLC, Decker Energy - Grayling LLC, Genesee Power Partners Limited Partnership, Hillman Power Company LLC, National Energy of Lincoln Inc. f/k/a Viking Energy of Lincoln LLC, National Energy of McBain Inc. f/k/a Viking Energy of McBain LLC, Tondu Corporation Thomas J. Waters	tjw@runningwise.com
Midland Cogeneration Venture LP John A. Janiszewski Madison S. Laskowski	 jjaniszewski@dykema.com mlaskowski@dykem.com
Other Robert O'Meara	 romeara@itctransco.com

Margrethe K. Kearney

Margrethe Kearney
Environmental Law & Policy Center
MKearney@elpc.org