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 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.

<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.

This EWR potential study has resulted in updated, expanded, and improved information on the Michigan customer base, and the potential for energy and demand

[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.

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 onereport 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 pages1 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]~~

~~Scenario #1: Sensitivity on Incentive Levels – GDS revised the basic analysis of Achievable~~

[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 Demand Response Statewide Potential Study portal on the MPSC's website: https://www.michigan.gov/mpsc/0,9535,7-395-93308_94792-552726--,00.html.**

~~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 thepotential 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]

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.

[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.**

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 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.~~

[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 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 studyintegrates 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 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 establishmaximum allowable concentrations for each criteria pollutant in outdoor air. Primary standardsare 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 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).

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.~~The 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)

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

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, tow 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 20222, 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

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

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 Cots Fining 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 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.[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 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 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 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, 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

[11] 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.

[12] 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.

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 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 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-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 EPA published the regulations on Octobr 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 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:

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 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, 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.~~

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 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 soueast Michigan had attained the standard using years 2019, 2020, 2021 ozone season data. The redesignation was put out for public comment in November 2120, and it is anticipated that the requiest will be submitted to USEPA in December 2021. Should USEPA approve the redesignation requiest, southeast Michigan will become maintenance for the 2015 ozone standard.

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.[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~~ **2031**" for the entire footprint.[14] MISO also calculates the local reliability requirement ofeach 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]

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

[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.

[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.

Requirement Study[20] 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.

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~~

[20] 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**

~~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.[21]
- **Moderate EV adoption and customer electrification result in moderate f**ootprint-wide[22] 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 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).

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[21] 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.

[22] 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.

- **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 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.[25]
- ~~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.**
- 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**.
- Technology costs for solar**, storage,** and other emerging technologies decline with commercialexperience.
- Existing PURPA contracts are assumed to be renewed.

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.[26]

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.

[25] 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.**

of two above the base case energy and demand growth rates. In the eventthat 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 sensitivityprojection, assume a 1.5% 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.**

(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 offour 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 that considers only legislatively mandated carbon goals and does not consider non-legislatively 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%

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

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.[29] 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.

~~**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.[30] 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 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 ownedby 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),~~

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

[30] ~~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.~~

~~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 reference case projections as projectedin the EIA's most recent Annual Energy Outlook reference case.[33]
- 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.**[34,35]
- ~~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 tax credits continue pursuant to current law.**
-

[33] 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.

[34] 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.

[35] 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.

- 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.

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. [36]

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.[37]

4. Ramp up the utility's EWR savings to at least 2.0%[38] of prior year sales over the course offour years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential.[39] EWR savings remain high throughout the study period.

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

6. **Carbon Price Sensitivity?**

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[36] 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.**
[37] **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/**
[38] **2021 Energy Waste Reduction Potential Study, Appendix D.**
[39] 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.

~~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[40] where natural gas prices near historical highs drive down domestic consumption and exports.~~
- ~~Footprint-wide[41] 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).~~
- ~~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:~~

1. ~~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.~~

~~[40] 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.~~

~~[41] 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.~~

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

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 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.~~

3. ~~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.~~

4. ~~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.~~[42]

[42] ~~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.~~

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

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 Potential Studies 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.

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.

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.

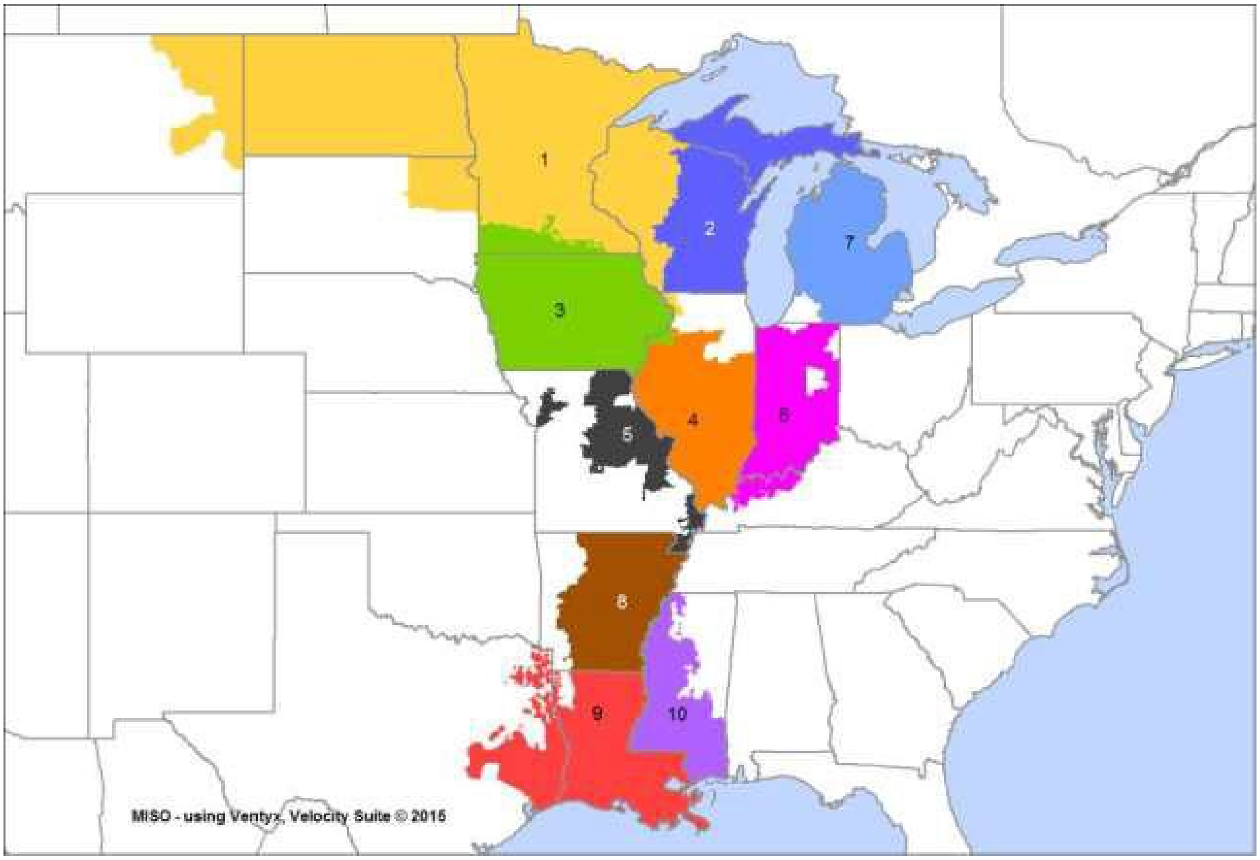
17. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the net present value of revenue requirements.

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



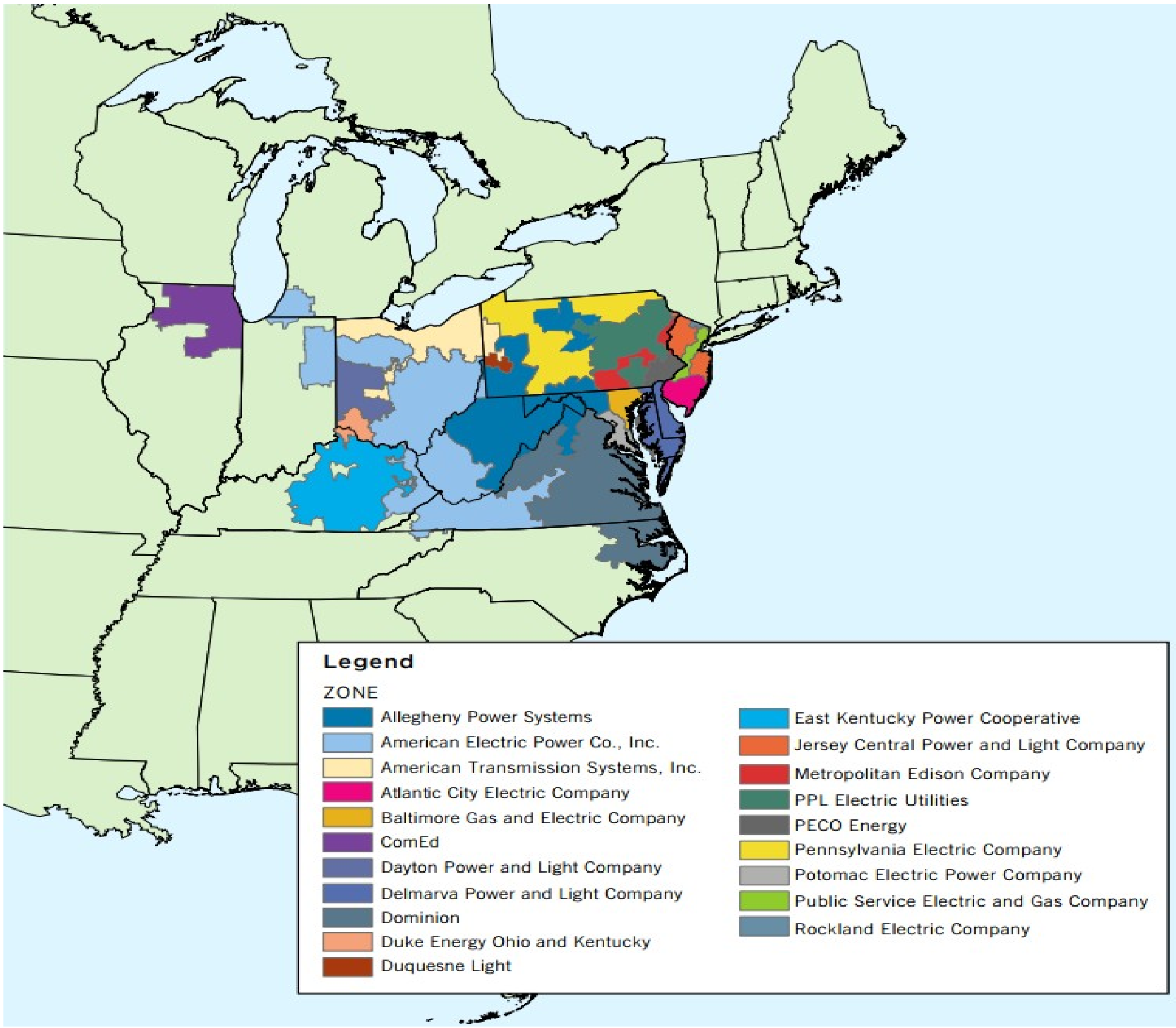
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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