Making the Most of Michigan's Energy Future

Integration of Resource, Distribution, and Transmission Planning Report

Michigan Public Service Commission Staff Report

MI Power Grid Phase II

May 27, 2021

Case No. U-20633

Michigan Public Service Commission

Acknowledgements

The Michigan Public Service Commission staff thanks the many individual stakeholders, experts, presenters, and panelists that contributed to the stakeholder process and assisted this workgroup in its efforts. Their participation and input contributed to the topics explored and was invaluable.

A list of organizations that participated in the stakeholder process or shared their expertise with Michigan Public Service Commission Staff is below. The list may not be comprehensive as not all participants shared their organizations. Thank you all for your participation.

Participating Organizations

5 Lakes Energy
Adams Bioprocess Services
Advanced Energy Companies
American Council for an Energy Efficient Economy
American Electric Power
American Municipal Power
American Transmission Company
Association of Businesses Advocating Tariff Equity
Bay City
Biomass Committee of the Michigan Renewable Energy
BM Environmental Ltd
Brand Energy
Center for Renewable Intergradation
Center Point Energy
Chart House Energy
Citizen Utility Board of Michigan
City of Ann Arbor
City of Marquette
Clark Hill (ABATE)
Clean Grid Alliance
Consumers Energy
Crystal Flash
Detroit Zoo
Dimension Renewable Energy
Direct Energy
Dominion Energy
DTE Energy
Duke Energy
Electric Power Research Institute
Energy Exemplar
Environmental Law & Policy Center
Fraser Trebilcock (SEIA)
Fraser Trebilcock Davis & Dunlap
GridLab
Guidehouse
Hawk Utility Consulting
Independent Power Producers Coalition of Michigan
Indiana Michigan Power Company
ITC Holdings
Key Capture Energy
Lawrence Berkeley National Laboratory
Mackinac Energy Center
Michigan Biomass Association
Michigan Conservative Energy Forum
Michigan Department of Environment, Great Lakes, & Energy
Michigan Electric and Gas Association
Michigan Electric Cooperative Association
Michigan Energy Innovation Business Council
Michigan Environmental Council
Michigan Environmental Justice Coalition
Michigan Public Power Agency
Midcontinent Independent System Operator
Midland Cogeneration Venture
National Renewable Energy Laboratory
Natural Resources Defense Council
New Energy Advisors LLC
Next Energy
Northern States Power Company

Northwest Renewable Energy Institute
NRG Business Solutions LLC
NRG Curtailment Solutions
Oakridge National Laboratory
Pacific Northwest National Laboratory
PJM Interconnection LLC
Plugged In Strategies
Public Sector Consultants
Regulatory Assistance Project
Renewable Energy Buyers Alliance
Renewable Energy World
Rivenoak Consulting
Ruben Strategy Group
Sierra Club
Swansen Leadership
Union of Concerned Scientists
University of Chicago Law School (Soulardarity)
Upper Peninsula Power Company
Varnum LLP
Vote Solar
Wolverine Electric Cooperative
Xcel Energy

Contents

Executive Summary

On October 17, 2019, the Michigan Public Service Commission (MPSC) launched MI Power Grid in collaboration with Governor Gretchen Whitmer. MI Power Grid is a customer-focused, multi-year stakeholder initiative intended to ensure safe, reliable, affordable, and accessible energy resources for Michigan's (State's) clean energy future. The initiative is designed to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. MI Power Grid encompasses outreach, education, and changes to utility regulation by focusing on three core areas: customer engagement, integrating new technologies, and optimizing grid performance and investments. The MPSC maintains a dedicated website for the initiative at www.michigan.gov/mipowergrid.

MI Power Grid seeks to engage a variety of stakeholders, including utilities, energy technology companies, customers, consumer advocates, state agencies, and others, in discussions about how Michigan should best adapt to the changing energy industry. Stakeholder groups are formed and led by MPSC Staff. This report highlights the efforts of the Advanced Planning Phase II, Integration of Resource, Distribution, and Transmission Planning Workgroup.

Under the goal of optimizing grid investments and performance, the MPSC introduced a three-phase approach towards evaluating electric resource, distribution, and transmission planning. Phase I focused on electric distribution planning. It involved a thorough stakeholder effort to provide further direction to the three largest utilities regarding their next filing of electric distribution plans in 2021. These sessions discussed a wide range of distribution planning topics including Non-Wires Alternatives (NWA) to traditional grid investments, Hosting Capacity Analysis (HCA) for consideration of Distributed Energy Resources (DERs) on the distribution system, and the value of resilience in relation to proposed investments. Phase II, which is the topic of this report, focuses on the integration of resource, distribution, and transmission planning. The goal of this report is to evaluate alternatives that provide the best value while resulting in a more efficient system and lower costs for ratepayers. Finally, the Phase III workgroup will specifically visit the Michigan Integrated Resource Plan Parameters (MIRPP), Filing Requirements, and Demand Response and Energy Efficiency Studies which are each required to be reevaluated every five years.

The energy landscape is rapidly changing, with the planned retirement of numerous fossil fuel generating units over the next decade, increased extreme weather events, and rapidly evolving DERs challenging regulators, utilities, and stakeholders to reevaluate current energy planning processes with a lens toward resiliency and efficiency. The Polar Vortex of 2019 has reinforced the need for Michigan to review the value of generation and resource diversity, and its role in respective planning processes. Load forecasting is the foundational building block upon which the utility planning system is based, and a critical first step in determining how much and when resources are needed.

Based on various statutory authorizations, commission orders, and the regional transmission organization's jurisdictions, separate processes exist for distribution, resource, and transmission planning. Since 2017, the Commission required Consumers Energy and DTE Energy to file five-year electric distribution plans (DPs) (1/31/17 Order Case No. U-18014) on staggered timelines. Indiana Michigan Power has since been required to file its five-year electric distribution plan through the Commission's Order in U-20147. Section 6t of Public Act 341 of 2016 (PA 341 or MCL 460) established that each investor-owned utility company was required to file an Integrated Resource Plan (IRP) that looks at anticipated electricity needs over 5, 10, and 15-year forecasts every five years, also on staggered timelines. Transmission planning for Michigan's utilities occurs through respective annual processes at the regional transmission organization (RTO) level, through MISO (Consumers and DTE Electric) and PJM (Indiana Michigan Power). While separate processes exist, Michigan could benefit from improved efficiencies with better alignment among these processes. The workgroup reviewed these processes and offered recommendations towards improved coordination.

The stakeholder process consisted of eight public forums held between September 2020-March 2021. Summaries of each meeting are available in Appendix A. Multiple experts and stakeholders were engaged throughout the process, ranging from utility panels, experts from national laboratories, transmission owners (TOs), and environmental, and clean energy groups. Informed by these meetings and participants' responses to feedback requests on specific topics, MPSC Staff made the following recommendations towards alignment of planning processes. Finally, this report provides an update on coordination efforts with the Department of Environment, Great Lakes, and Energy (EGLE) on the inclusion of public health as an environmental justice (EJ) in IRPs, as well as an update on emissions reporting recommendations for complying with Michigan's goal of reducing carbon emissions by 28% by 2025. A summary of these recommendations is below.

Summary of Recommendations

Resilience

- Direct utilities to identify vulnerable loads in their distribution plans.
- In a future distribution planning stakeholder session, discuss the potential value that the following would provide regarding reliability and resilience in areas of vulnerable populations: 1) environmental justice screening tool, 2) the use of Customers Experiencing Multiple Interruptions (CEMI) metrics, and 3) Customers Experiencing Long Interruption Duration (CELID) metrics.

Forecasting

- Increase internal communication.
- Create/improve internal communication between utility departments to ensure forecasting methodologies, data, and assumptions are aligned across the utility organization.

- Increase forecast consistency by illustrating forecast alignment and provide evidence that supports the Company's approach to increasing consistency between forecast components across planning processes.
- External Transparency
    - Provide forecast methodologies for all forecast components.
    - Share public sources used when available.
    - Clearly document in the filing or workpapers how forecasts have been revised from one case to another across all cases filed at the Commission.
- Take a componentized approach to creating all forecasts used in the IRP model, clearly documenting the assumptions, data, and methodology used for each component.
- Where there are limitations in the ability of a particular planning model to capture all potential value streams of a resource, resource decisions should be supported by modeling results from separate modeling processes that allow for adequate consideration of all value streams of a resource, where reasonable and applicable.
- Recommend further discussion in future distribution planning workgroups to align forecasting.

Transmission Planning

- Enhanced Communication
    - Facilitate information sharing between utilities and transmission owners with a minimum of biannual meetings.
- Information Transparency
    - Use information from the most recent Regional Transmission Operator (RTO) reliability planning models when possible.
    - Work collaboratively with the transmission operator (TO) and evaluate and provide results. Include transmission related reports in filing to the extent possible.
    - Encourage Stakeholder Participation in Existing Transmission Planning Processes.
        - Participation in RTO processes will increase awareness of regional initiatives, regional reliability, and broad impacts of fleet changes.

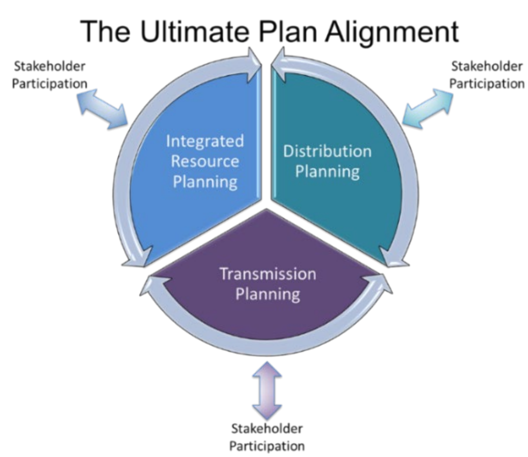
Value of Generation Diversity

- Risk Assessment
    - Conduct a stochastic risk assessment for each optimized plan.
    - Tests resource portfolios optimized for a single future against a wide range of alternative future conditions.
    - More accurately value risk mitigation.
- Propose deterministic scenarios to evaluate specific futures.
- Utilities should still conduct their own deterministic analyses in addition to stochastic and prescriptive deterministic scenarios but should be supported each instance as reasonable for evaluation of a particular future.
- Utilize graphing to illustrate results such as Box and Whisker Plots.

  - Internally track state-wide generation diversity.
  - Continue collaboration with stakeholders to further develop MPSC Staff's (Staff's) understanding of generation diversity and risk assessment.

Alignment of Distribution Planning/IRP/Transmission Planning

- Increase consistency between DPs and IRPs.
  - Forecasting assumptions and modeling scenario results should clearly feed from one plan to another and vice versa.
  - Timing between DP and IRP are coordinated to increase transparency.
- Increase communication between all interested parties.
  - Between utilities and stakeholders through stakeholder outreach and technical meetings before, between, and during cases.
  - Between transmission, distribution, and resource planning organizations. Include evidence of these discussions in cases.
- Utilities should consider aligned organizational structure.
- Planning should not only align, but iteratively feed into one another:
  - DP should include a needs assessment that supports certain IRP resources.
  - Resources selected in an IRP that can provide benefit to a distribution grid should be tied back to locational distribution needs in the distribution plan to the extent locational need is identified.
  - Transmission planning should clearly align with both resource and distribution planning.



The ultimate plan alignment occurs when distribution planning, resource planning, and transmission planning are iterative with ample opportunities for stakeholder engagement throughout each planning process. The constant flow of information facilitates understanding and opportunity for input within organizations, between organizations and with stakeholders.

Emissions Recommendations and Environmental Justice Considerations

- Staff recommends that further consideration be given to counting carbon for market resources during Phase 3 of the Advanced Planning workgroup, when the draft MIRPP and IRP Filing Requirements are discussed.
- Continue meetings and coordination between MPSC and EGLE technical staff.
- Continue coordination and development of a list of additional environmental data requests for utilities to include in upcoming IRPs.

Introduction

Energy laws enacted in 2016 focused on adaptable planning processes, cleaner energy supply resources, and ensuring that demand-side resources are on an equal playing field with supply-side resources. Specifically, Section 6t of Public Act 341 (PA 341 or MCL 460) laid out directional guidance for rate-regulated utilities to submit Integrated Resource Plans (IRPs) to the Michigan Public Service Commission (MPSC or Commission) for review and approval, on five-year schedules.[1] In its April 12, 2018 Order in Case No. U-20147, the Commission directed the three largest rate-regulated utilities to file electricity distribution and maintenance plans every five years. While transmission planning is included as subsection XII of the IRP Filing Requirements,[2] transmission planning discussions largely take place through the workgroups of Michigan's RTOs: The Midcontinent Independent System Operator (MISO) Transmission Expansion Planning (MTEP) Process and the PJM Regional Transmission Expansion Plan (RTEP) Process.

Following the challenging 2019 January Polar Vortex, Governor Gretchen Whitmer requested the Commission to conduct a review of the State's supply, engineering, and deliverability of natural gas, electricity, and propane. The Commission, in its September 11, 2019 Order in Case No. U-20464, accepted and adopted a finalized version of the report, called the Statewide Energy Assessment (SEA). In the SEA, the Commission made multiple recommendations to mitigate risks for the safe and reliable delivery of energy. One of the report's suggestions was for a more cohesive and holistic planning process aligning the various Distribution Plans, Transmission Plans, and integrated Response Plans (IRPs).

The Commission's MI Power Grid initiative directed Staff to conduct a series of stakeholder collaboratives examining these issues. This report seeks to draw key learnings and recommendations for aligning Michigan's utilities planning processes and to provide a basis for the Commission's further exploration into revisions of the Michigan Integrated Resource Planning Parameters (MIRRP) and filing requirements.[3]

---

[1] Reference to Public Acts 341 and 342 of 2016. Docket No. U-18418 established the initial process for MPSC Staff and stakeholders to develop the Michigan Integrated Resource Planning Parameters and IRP filing requirements.

[2] Commission order in Case No. U-18461 and U-15896, December 20, 2017, Exhibit A, pp. 17-18.

[3] Michigan Integrated Resource Planning Parameters were developed as part of the implementation of PA 341, Sec 6t. It provides the required IRP modeling scenarios and sensitivities for rate-regulated utilities to use when conducting its IRP. The statute requires these modeling scenarios and sensitivities, applicable reliability requirements, applicable environmental rules and regulations, demand response, and energy waste reduction studies be re-examined every five years, or by July 2022.

MI Power Grid Initiative- Introduction, Objectives, and Methodology

With an eye toward the changing landscape of the electric system, the Commission launched MI Power Grid. Supported by Governor Whitmer, this effort is a focused, multi-year stakeholder initiative to maximize the benefits of the transition to clean, distributed energy resources for Michigan residents and businesses. In its October 17, 2019 Order in Case No. U-20645, the Commission outlined the initiative's three core areas of advancing Customer Engagement, Integrating Emerging Technologies, and Optimizing Grid Investment and Performance. Advanced Planning is a key aspect of the Optimizing Grid Investments and Performance tranche.

Background Orders

The Commission charged Staff to examine the alignment of Michigan's Integrated Resource/Distribution/Transmission Planning (Advanced Planning) efforts. Staff conducted a series of stakeholder meetings from September 2020 to March 2021. As directed by the Commission, these sessions addressed the following areas:

- Identifying potential ways to align distribution plans with IRPs and examination of best practices from other jurisdictions, including:
    - Methodologies to develop distributed energy resource (DER) forecasts over a five and ten-year period;
    - Potential sources or methodologies to forecast electric vehicle (EV) penetration over a five and ten-year period;
    - Methodologies or frameworks to forecast the impact of the expected EV penetration on the load forecast over a five and ten-year period; and
    - Methodologies or frameworks to evaluate non-wires alternatives (NWAs) such as targeted energy waste reduction and demand response in distribution plans and integrated resource plans.
- Identify potential revisions to the Commission-approved IRP modeling parameters or the filing requirements to better accommodate transmission alternatives in IRPs in preparation for the next formal review of the MIRPP expected to take place in 2022.
- Identify methodologies to quantify and value generation diversity in IRPs.

In addition, the Aug 20, 2020 Order in Case No. U-20633, directed Commission Staff to:

- Coordinate with the Department of Environment, Great Lakes, and Energy (EGLE) on the inclusion of public health and environmental justice considerations in future integrated resource planning cases.
- Provide a status update on actions into this docket filed no later than May 27, 2021.

Through the workgroup efforts, Staff engaged over 20 subject matter experts that represent national laboratories, federal research institutions, utility companies, transmission companies, environmental groups, various consultants, and stakeholders. Each meeting averaged four hours in length and engaged stakeholders with facilitated discussion and expert presentations. Following most of the workgroup presentations and discussions, Staff posted "stakeholder feedback requests," which posed additional questions requesting written feedback that expanded on the relevant topics explored. A summary of each meeting is available in Appendix A.

This Staff report summarizes the entire stakeholder effort and is organized into five main subsections: Forecasting, Transmission Planning, Value of Generation Diversity, Alignment of IRP/Distribution Planning/Transmission Planning, and Emissions and Environmental Considerations.

Each of the subsections introduces the topic by referring to applicable background statutes and prior Commission orders, discusses the key topics explored by subject matter experts and stakeholders, and concludes with Staff's recommendations. Many of the topics explored during the Advanced Planning stakeholder meetings, and contained within the report, are expected to provide foundational background for a future report later this year, which will work on building consensus towards revised Michigan Integrated Resource Planning Parameters (MIRPP)[4] and IRP Filing Requirements (Filing Requirements).[5]

Executive Actions

On Sept. 24, 2020, Governor Whitmer issued a series of executive directives and orders committing Michigan to the U.S. Climate Alliance and directing EGLE to develop an implementation plan to meet the environmental goals established in the executive directive. The most impactful result of these executive actions on the work of the Advanced Planning workgroup was the goal established in Executive Directive 2020-10 (ED 2020-10),[6] for Michigan to achieve a 28% reduction to economy-wide carbon emissions, compared to 2005 levels.

The Commission responded to ED 2020-10 by issuing additional guidance in its Oct. 28, 2020 Order in Case No. U-20633, instructing Staff to incorporate the following:

- Include consideration of how to implement the Governor's emission reduction goals into its recommendation for updating the utility planning process.
- Present a straw proposal to the workgroup, to solicit alternative proposals from interest parties, to solicit comments from stakeholders on the proposals presented to the group,

[4] Commission Order in Case No. U-18418, November 17, 2017, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UYSyAAO. Retrieved April 14, 2021.
[5] Commission Order in Case No. U-15896, December 20, 2017, *Exhibit A. IRP Filing Requirements*, p. 4.
[6] Executive Directive 2020-10, https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html. Retrieved April 14, 2021.

and to summarize and provide its recommendation for a final proposal for utility IRPs to reflect these emission goals.

- Develop recommendations as to both utilities filing before updates to the MIRPP and IRP filing requirements are finalized, as well as those filed following the updates.
- File a Staff report on recommendations no later than Dec. 15, 2020.

The MPSC Staff Report, "Emissions Reporting Requirements for Utility IRPs," was filed accordingly, and the report and appendices were filed in the docket for Case No. U-20633.[7] On Feb 18, 2021, the Commission issued its guidance on emissions to be included in the IRPs, which is included in the Emissions and Environmental Considerations section of this report.

Foundational Definitions

When working to align planning processes, it is important to define key terms. This ensures that stakeholders, Staff, and utilities are all able to understand one another when discussing ideas for aligning planning processes. For this reason, Staff has adopted the same definitions for the Advanced Planning Process as were used in Staff's Electric Distribution Planning Stakeholder Process report issued April 1, 2020, which the Commission adopted in the Commission's August 20, 2020 Order in U-20147.

- **Distributed Energy Resource (DER)** – A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.
- **Hosting Capacity Analysis (HCA)** – Amount of DER that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades.
- **Non-Wires Alternatives (NWA)** – An electricity grid investment or project that uses distribution solutions such as DER, energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.
- **Locational Value Assessment** – Locational value assessment is intended to quantify the benefits and costs of DER, which are often locational and time varying in nature.

Defining Resilience

The SEA report highlighted several recommendations that pertained to resilience. These included recommendations for propane, gas, and electric infrastructure. When addressing gaps in existing planning, operational, and emergency response processes that present opportunities to improve safety, reliability, and resilience, the Commission noted that, "[u]nderstanding the value of resilience improvements will better inform future Commission decisions on investments targeting

[7] *Emissions Reporting Requirements for Utility IRPs*, https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000HwJydAAF. Retrieved April 22, 2021.

resilience improvements. Resilience, or the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event, is a broad concept."[8]

The topic of resilience was front and center in the Distribution Planning Stakeholder Process workgroup and a session was dedicated exclusively to discussions on the topic. Two resiliency experts spoke at this session. Both experts addressed resilience differently; one highlighted recovery from catastrophic or extraordinary events, and the other discussed resilience as avoidance of interruptions altogether. In response to the Staff report on distribution planning, the Commission addressed resilience again in its Order in Case No. U-20147. In that Order, the Commission embraced DTE Electric's description of resilience in terms of the ability to restore power following a catastrophic event. The Commission added to DTE Electric's description of resilience, "[t]he Commission also thinks about this term more broadly such as planning to mitigate more localized, high-impact outages caused by equipment issues, access limitations, or system configurations that inhibit timely restoration or back-up capabilities."[9] The Commission specifically highlighted consideration of the vulnerability of loads that would affect public health, safety, or security.[10] The Commission's description addressed both restoration and avoidance of outages while requiring the consideration of locational vulnerability. This is synchronous with the Presidential Policy Direction 21 that defines resilience as, "the ability to prepare for and adapt to changing conditions and withstand and recover rapidly from disruptions. Resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents."[11]

Resilience was not directly addressed during the series of work sessions in the MI Power Grid Advanced Planning Workgroup; however, it was inherently embedded in conversations about aligning planning practices and generation diversity. Often, stakeholders commented about investments, such as DER, having reliability and resiliency benefits. Staff finds that reliability and resilience continue to be used interchangeably by experts and stakeholders in many different forums. This makes the concept of resilience difficult to differentiate from reliability and therefore discuss. It also makes it challenging to value the standalone benefits of resiliency among stakeholders, utilities, and Staff.

When discussing resilience in this report, Staff is referring to the guidance provided in the Commission Order in Case No. U-20147, including both restoration from an outage and avoidance of an outage. Staff, stakeholders, and utilities still fall short of clearly distinguishing between

---

[8] Statewide Energy Assessment Final Report, https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf, retrieved April 2, 2021, p. 187.
[9] Commission Order in Case No. U-20147, August 20, 2020 p. 48.
[10] Id. p. 49.
[11] Presidential Policy Directive – Critical Infrastructure Security and Resilience, February 12-2013.

reliability and resilience explicitly. However, Staff does find that the concept of resilience is measured as part of existing reliability metrics, along with additional metrics for Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID) that were recommended by Staff in the Electric Distribution Planning Stakeholder Process report.[12] These reliability metrics specifically address recovery and restoration from outages. Avoidance of outages is inherently measured through illustrating a trend that includes fewer outages over time as infrastructure, resource, and technology investments are made. In fact, it may not be necessary to distinguish between reliability and resilience to value investment. Rather, it may be more beneficial to understand the attributes of reliability investment that inherently impact system resiliency for vulnerable loads that affect the health, safety, and security of the public. To this end, resilience could be thought of as those investments that maintain critical infrastructure and services like safe water, sanitary services, emergency response, hospitals, and communication during high impact, low probability events.

Resiliency events tend to be major events that that have a low probability of occurring. However, the benefits of resilience investments are often hyper-localized in nature, benefitting even a singular customer. For instance, back-up generation and storage on an industrial customer circuit provides resiliency to that customer site. Similarly, back-up generation and storage at a hospital provides resiliency to the hospital as a customer. It also provides benefits to the general public by enabling critical services during resiliency events. In the case of the critical infrastructure and services, many resiliency investments have been made that enable those vulnerable loads to continue to be served even during an event. In addition to serving vulnerable loads as identified above, there could be a framework for evaluating resiliency investments for non-vulnerable loads by also considering the other grid benefits that investment may provide. An example is an investment in back-up power that provides peak shaving that in turn differs distribution investment.

As Staff continues to think through the Commission's direction to consider the vulnerability of loads and analyze the relationship between load vulnerability and resilience, two aspects of load vulnerability come to mind. One is related to the system and its vulnerability to adverse conditions such as deliberate attacks, accidents, or naturally occurring threats or incidents. The other aspect is to consider providing resilient service to vulnerable loads that provide the public with safe water, sanitary services, hospitals, emergency response and communications that in turn impact people more severely during outages. Staff notes that EGLE has been working on an environmental justice screening tool, which will be discussed later in this report, that utilities could use to identify where there are vulnerable populations within their service territory as one way to start to identify vulnerable loads. This tool could facilitate the ability to measure CEMI and CELID in areas of vulnerable population. However, the tool is designed as an environmental justice screen, so it does

[12] Electric Distribution Planning Stakeholder Process report filed in Case No. U-20147, April 1, 2020, p. 32.

not necessarily identify the vulnerable loads which provide for public health, safety and security. Staff also has identified a framework that may provide some insight as to how to consider resiliency in Michigan. PNNL conducted a workshop in Hawaii that was focused on the role of storage and microgrids in supporting electric system resilience. Although the electric grid of Hawaii is vastly different than Michigan, the basic elements of the framework warrant consideration.[13,14] The first step of that framework is to identify critical loads.

After reviewing the Planning Considerations for Energy Storage in Resilience Applications framework, the Presidential Policy Directive 21 definition of resilience, and previous Commission guidance, Staff recommends that utilities identify vulnerable loads within their service territory to foster discussion with Staff, stakeholders, and regulated utilities about how best to ensure those loads are integrated into planning processes. This includes the assurance of reliable and resilient service for those vulnerable loads that ultimately provide services the public depends upon. Staff also recommends that Staff, stakeholders, and regulated utilities discuss the potential value that the environmental justice screening tool can provide when considering vulnerable populations and the use of CEMI and CELID metrics that could be applied as local reliability and resilience metrics to areas where there are vulnerable populations are identified in any future distribution planning stakeholder sessions.

Forecasting

Background and Summary

The load forecast is the foundational building block which provides the basis for utility system planning. It is the critical first step that determines both how much and when resources will be needed. The use of a suboptimal load forecast will lead to suboptimal planning. Utilities use load forecasts with a variety of different time horizons for a variety of different purposes. Short-term forecasts (sub-hourly, day ahead, etc.) are necessary for grid operation. Long-term forecasts are used for system planning over several years and are the focus of this workgroup.

Fundamentally, load forecasting is the analysis of the relationship between electric load and those variables that affect electric load. Variables affecting electric load include economic, technological, regulatory, and demographic factors. Load forecasting has always been complicated, but the

---

[13] Planning Considerations for Energy Storage in Resilience Applications, Outcomes from the NELHA Energy Storage Conference's Policy and Regulatory Workshop, http://energystorage.pnnl.gov/pdf/PNNL-29738.pdf, last visited May, 5, 2021, pp 2.11-2.12.

[14] Planning Considerations for Energy Storage in Resilience Applications highlights five guiding principles that form this framework for an approach to resilience. 1) Define critical loads; 2) Identify major events of concern; 3) Establish planning objectives; 4) Engage in iterative planning between the project and the local grid to meet the needs of both; and 5) Throughout the process, consider questions of ownership, cost allocation and rate design.

transition of utility systems towards distributed energy resources and increasing amounts of intermittent generation magnifies that complexity. The number of variables and assumptions necessary to construct an accurate forecast has increased as technologies such as electric vehicles, building electrification, DERs, NWAs, and behind-the-meter-resources have become more commercially available. Weather also has a major effect on electric load. Typically, load forecasts used in long term planning are based on normal weather. Ensuring a representative weather forecast is continually more important given increasing extreme weather events,[15] as well as anticipated increases in the amount of intermittent generation, such as wind and solar generation, serving the electric system whose performance is directly tied to weather conditions. Long-term load forecasts are a critical component in utility planning functions, including a variety of regulatory proceedings. Examples include IRPs, distribution plans, transmission planning (at the RTO level), rate cases, EWR cases, power supply cost recovery cases (PSCR), renewable energy plan cases, capacity demonstration cases, and peak load contribution calculations (at the RTO).

Over the past few years, the Commission has provided guidance on forecasting in several of these proceedings. In recent electric rate cases for both DTE Electric Company and Consumers Energy Company, the Commission has looked to Staff to:

> "engage with stakeholders on the topic of EWR, and sales forecasting through the EWR collaborative, or other forums in the future. The topic of offsets to EWR savings is ripe for further analysis and discussions given the reliance on EWR as a resource and the importance of load forecasting accuracy to planning, reliability, and rate setting."[16,17]

The Commission addressed forecasting in DTE's Certificate of Necessity Case No. U-18419, identifying some forecasting considerations, including "among other things, effects of demand-side management, environmental limitations, planning reserve margin and system reliability requirements, or other legislative or societal developments that will likely impact future energy requirements."[18]

The Commission also addressed forecasting in utility distribution plan cases. [19]

> "The Commission emphasizes the importance of accurate forecasting in planning and investment decisions and the need to ensure best practices in forecasting

---

[15] Michigan Public Service Commission. (2019, September). *Michigan Statewide Energy Assessment, p. 15*. https://www.michigan.gov/documents/mpsc/2019-09-11_SEA_Final_Report_with_Appendices_665546_7.pdf.

[16] Commission Order in Case No. U-18255, April 18, 2018, p. 36.

[17] Commission Order in Case No. U-18322, March 29, 2018, p. 50.

[18] Commission Order in Case No. U-18419, April 27, 2018, p. 40.

[19] Commission Order in Case No. U-20147, November 21, 2018.

methods as technologies and customer behavior evolve with the adoption of DERs and plug-in electric vehicle (PEV) charging, which may include scenario-based forecasting to account for uncertainties and identify least-regret solutions. Whether it is at the bulk transmission system or the individual distribution circuit level, the Commission believes prudent planning and investments will require more sophisticated forecasting approaches to develop best practices and mitigate risks. The Commission seeks to avoid prescribing specific methods or approaches in the next round of distribution plans but acknowledges that the Staff's recommended dynamic approach to load forecasting with scenario analysis could help better understand and accommodate uncertainty associated with DERs, PEV charging, and other factors. The Commission encourages continued discussion of forecasting methods to inform the next iteration of distribution plans."

Discussion

Forecasting Components

As mentioned above, increasing complexity in the electric system has enhanced the complexity of load forecasting. Utility planning has traditionally been focused on serving gross electricity demand and energy by building, or acquiring, centralized base-load generation while constructing distribution and transmission infrastructure to transmit and deliver those resources. However, DERs and NWAs may provide a new opportunity for increased reliability and affordability without the costs associated with traditional solutions. To adequately assess the value of these resources and determine the role various technologies should play in serving load, utilities must start with an accurate net load forecast that identifies the needs of the utility's system. When developing a forecast, the utility must clearly understand which technologies are available for the planning model to select as resources to serve load, and which technologies are modeled as modifications to the overall load shape. In some cases, the same type of resource could be modeled as an adjustment to load and that same type of resource could also be available for the model to select during a resource optimization run. For example, distributed solar includes both customer-owned rooftop solar, and utility owned solar connected at the distribution level. Customer-owned solar would result in a need to adjust the load forecast, based on anticipated adoption rates and electric generation profiles. Utility owned solar connected at the distribution level can be input into the model as potential resource to allow the model the ability to select it when optimizing a resource solution. It may be possible that a resource allows for the deferral of distribution or transmission investment and provides unsurmountable benefits such that it is forced in the model on an economic analysis basis. In all cases, it is important that the utility is clear and transparent with their methodology and assumptions so stakeholders and Staff understand and can contribute to the discussion about methodology and assumptions.

The net load forecast can be thought of as a gross demand and energy forecast that is then adjusted by several separately forecasted components. Forecasting components could include building electrification, electric vehicle adoption, behind-the-meter resources, EWR, and any demand side resource that is not directly controlled by the utility and dispatched by the market. All of these forecasted components are in effect inputs to the model. The modeling process selects resource outputs. It is important that DERs and NWAs are treated equitably and economically when compared to other resource possibilities analyzed in an IRP, which is used to select the most reasonable and prudent resources. If DERs and NWAs are not equitably valued in comparison to other capacity additions, then they will continue to be incorporated into the resource plan as an afterthought and the value they provide to the system may not be fully accounted for. Part of ensuring that these resources have an equitable valuation requires consideration of the revenue requirements, i.e., cost to customers, presented by these resources.

Forecasting components separately and then aggregating them into a net load forecast produces valuable results such as creating a clearer understanding of the individual impact of each forecast component and associated assumptions about the overall forecast. Separately forecasting components also provides the flexibility to adjust certain components individually in various scenarios and sensitivities for further analysis.

Distributed Energy Resource Forecasts

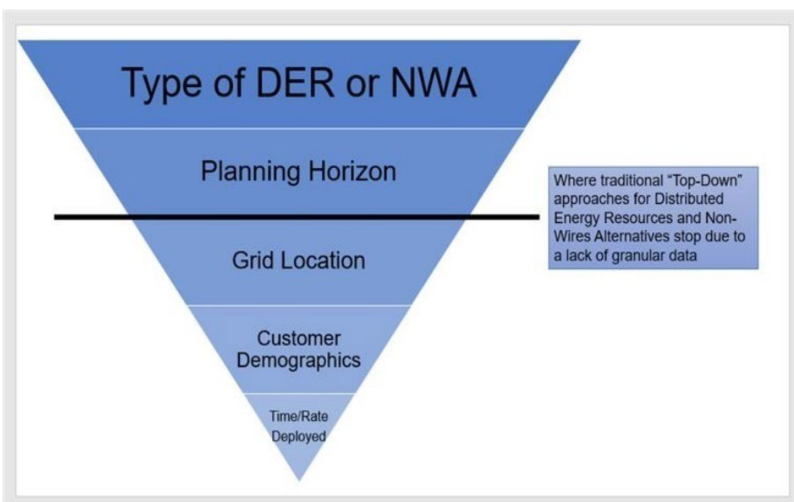
DER along with EWR and DR forecasts in IRPs have traditionally been done with a "top-down" approach, and the specific locations of grid connection for DERs, EWR, and DR may be unknown. This lack of data contributes to the limited knowledge about the localized benefits for DERs and NWAs, which impacts the ability to analyze the potential grid benefits that result from a reduction in capacity needed to serve load. Capturing data is further complicated for EWR and DR programs that adjust load and are time dependent, as customers control the rate they are deployed and how they are used. It also reinforces the necessity for all components to be properly weighted when conducting long term energy forecasts, as they can provide varying levels of impact depending on location on the grid and time of use. In cases where this data can be collected through surveys, utilities are just beginning to use it to identify solutions.

NWAs are a combination of DER and load-modifying resources deployed to address grid needs in lieu of conventional utility capital investment. Load and DER forecasts are the basis for identifying grid needs, and NWA are designed to address the needs. In other words, NWA are not forecasted, but rather deployed in response to a known grid need. Although, DERs may also be selected as modeling outputs, placing them in a specific location that supports a known grid need can also classify them as an NWA.

The ability to forecast adoption rates of different DER technologies separately from one another is also important. The current aggregated approach for forecasting DERs, EWR, and DR does not allow for equitable treatment. In its August 20, 2020 Order in Case No. U-20147, the Commission stated it is "important to run sensitivities in load forecasts for distribution planning and to start modeling locational impacts from customer behavior (whether through plug-in electric vehicles, EWR, storage, solar distributed generation, DR, etc.)."[20] Curt Volkmann provided a suggestion during his presentation on December 16, 2020 regarding DERs. Mr. Volkmann suggested that the Commission require a series of questions to be answered in utilities' next five-year distribution plan to improve forecasting.[21] These questions include:

1. How are they forecasting load and DER?
2. How do they plan to improve load and DER forecasting going forward?
3. How are DER and load forecasts integrated?
4. How do they incorporate stakeholder engagement into forecasts?

Staff agrees and recommends utilities provide additional information in future IRPs and Five-Year Distribution Plan cases on load and DER forecasting and/or modeling to better align the two planning processes. Specifically, Staff would like to see, to the extent possible, greater granularity as to where on the system DERs are interconnected and where NWAs may be beneficial to the system. Treating DERs and NWAs as resource options in modeling requires granular data collection at the user level for a utility's customer base. This data includes temporal load profile, location on the grid, and avoided cost calculations. If DR is not a resource the model is evaluating, then it should be accounted for in the forecast as accurately as possible.



As discussed above, analytical tools have been proposed during the MI Power Grid Advanced Planning stakeholder sessions to help utilities ensure consistent, accurate forecasting across the planning process. Tom Eckman presented that, "system expansion models used to estimate avoided costs should include all resources so the model can select them for development when determining impact of widespread deployment of demand flexibility."[22] Staff agrees and recommends that utilities explore more granular DER and NWA forecasting programs or tools for modeling these specific resources.

---

[20] Commission Order in Case No. U-20147, August 20, 2020, p. 49.
[21] MI Power Grid Advanced Planning Meeting, December 16, 2020.
[22] MI Power Grid Advanced Planning Meeting, December 16, 2020.

Electrification

Another critical forecasting component that was discussed throughout this workgroup was electrification of buildings and transportation. Assumptions about electrification was one of the key issues considered when determining how best to incorporate the climate goals identified by Governor Whitmer in ED 2020-10. Assumptions and forecasting of electrification are especially important when considering the Governor's goal of economy wide carbon neutrality by 2050. Achieving that goal would likely require electrification of nearly all the transportation and building stock within the State. Assumptions about how the load and load shape would evolve will have a significant effect on modeling results. The IRP study period requirement in MCL 460.6t is 15 years, which does not extend to the 2050 goal identified in ED 2020-10. However, due to the long useful lifespans of existing assets and slow adoption rates of new technologies, electrification of transportation and buildings would need to be accelerating before this time to reasonably achieve the target. As the plans to meet the goals set forth in ED 2020-10 are determined, assumptions around electrification in IRP modeling can be better identified. As discussed in further detail later, the near-term recommendation is that utilities are consistent across planning efforts and transparent with stakeholders on the electrification component within their load forecasts. Utilities will file updated IRPs at least every five years. Likewise, the assumptions around electrification must also be revisited and updates as more information continues to become available with each IRP cycle.

Consistency

Consistency of system-level forecasts across planning processes was one of the key themes identified in this workgroup. Several subject matter experts pointed towards consistency of system-level forecasts as a critical step toward aligning planning efforts. This idea is also discussed in several recent industry publications. "System-level DER and load forecasts are primary inputs to both resource planning and distribution planning. These forecasts reflect macroeconomic trends, policy changes, retail rates, technology advancements, and diffusion patterns."[23] Aligning distribution planning with resource and transmission planning begins with consistent system forecasts and scenario assumptions. "Appropriate data sharing and coordination of forecasts between distribution, transmission, and other associated functions in electric companies will be important to accurately capture both macro- and micro-level drivers. Conducting future resource planning in this more integrated manner will also require internally consistent forecasts and assumptions."[24]

Aligning forecasts across planning processes is complicated by the fact that the various planning processes may differ. The study period of a distribution plan might not be the same duration as a

[23] PNNL Next-Generation Distribution System Platform Initiative (DSPx) Modern Distribution Grid Strategy and Implementation Planning Guidebook pp. 24-25.
[24] EPRI Developing a Framework for Integrated Energy Network Planning (IEN-P) p. 40.

resource plan or transmission plan. The granularity of forecasts necessary for planning is also a function of the goals and scope of the various planning processes. Typically, distribution planning requires much more granular, circuit-level, load forecasts whereas resource planning can be accomplished with only the broader, system-level, load forecast. Differences in filing schedules, and by extension, the time when input data is being collected, the type and scope of modeling being completed, and the specific solutions that are considered, may determine the best available input data.

As a default, underlying assumptions and drivers used in system-level forecasts should be consistent from one planning process to the next. The system-level assumptions used in the base forecast for an IRP should be consistent with those used in a distribution plan and, for time periods covered by both plans, completed at roughly the same time. Scenario analysis might alter these assumptions and/or drivers to analyze different futures, but a reference forecast in one process should be based on the same assumptions and drivers as the reference forecast in another process.

Utility filings with the Commission should illustrate forecasting alignment and provide evidence that supports the Company's approach to maintaining consistency between forecast components across planning processes. As forecasts evolve, containing additional or updated data or new assumptions, filings should include a description of what has changed and justification for those changes. The relationship between forecasts used in one planning effort and subsequent planning efforts should be clear.

Other relevant utility regulatory filings that use forecasts similar to, or derived from, resource, distribution, and transmission planning (e.g., power supply cost recovery plans, EWR plans, rate cases, renewable energy plans, RTO Resource Adequacy Construct, RTO Peak Load Contribution, etc.) should use forecasts consistent with those used in recent planning processes. Utilities should show within these regulatory processes how the forecast is consistent with recent planning processes. If there are differences, these should be clearly identified and justified in each of the respective filings.

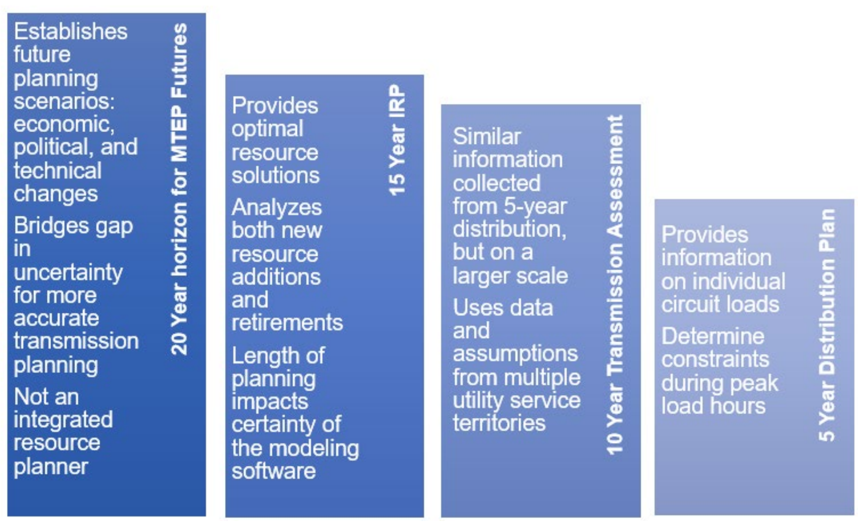
Forecast Time Horizons

Michigan's electrical system planning primarily consists of three separate planning processes: IRP with a 15-year planning period (at a minimum), distribution system planning through five-year distribution plans, and transmission planning through both the Transmission Owner's (TO) 10-year assessments, as well as at MISO through its MTEP process and PJM RTEP process. There are also several other regulatory processes within the MPSC that are related to one or more of the planning processes. The type of relationship varies. However, information generated from the planning process is critical to the other regulatory proceeding, or vice versa. Examples of these separate but related regulatory proceedings were mentioned in the previous section and included rate cases, power supply cost recovery plan and reconciliation cases, EWR plan and reconciliation cases, and DR reconciliation cases. The time horizon, or the length of time over which the model performs its analysis, of each process has impacts on the results of these processes and has the potential to complicate the integration of the different processes or the results together. Additional timing considerations such as the assumed measure or resource life can have significant implications on the resulting planning solutions.

Current Time Horizons for Planning Processes

Each planning process is conducted and updated under timeframes established through either legislative or regulatory guidelines. Utilities file updates to their IRPs with the Commission at least every five years, as required under MCL 460.6t.[25] The timing for distribution plans is established in Commission orders; most recently in its August 20, 2020 Order in Case No. U-20147, the Commission instructed Consumers Energy, DTE Electric, and Indiana Michigan Power Company (I&M) to file their next distribution plans by September 30, 2021.[26] On a regional level, MISO conducts its MTEP process on an annual basis; TOs, distribution utilities, Staff and other stakeholders participate in the MTEP planning process, where transmission and non-transmission solutions to identified system needs are analyzed and discussed. To inform these solutions, TOs conduct their own transmission system analysis and provide updates to the Commission Staff informally each year. Integrating these processes together is complicated by the differences in timing of updates to these processes.

Due to the different objectives of each process and the different components of the electric system being analyzed, the modeling in each of these processes utilizes a different time horizon. For example, utility IRPs, which attempt to provide the optimal resource solution to meet the utility's load requirements and other performance metrics, are conducted using a 15-year time horizon.[27] Distribution plans require a five-year time horizon, as specified in Case No. U-20147, but are sometimes refreshed more frequently than five years. IRPs consider both new resource additions and the retirement of existing resources, so IRP time horizons must allow for adequate lead times for successful unit retirement and planned replacement while also balancing the increasing risks associated



---

[25] MCL 460.6t, Section 3.

[26] Commission Order in Case No. U-20147, August 20, 2020.

[27] MCL 406.6t, Section 3.

with long-term cost and performance forecasts. Distribution plans are concerned with the loading on individual circuits, typically looking for constraints on circuits during peak load hours in the short to medium term. Like distribution system planning, the objective of transmission system planning is to analyze the system for constraints or other reliability issues during peak hours. The main difference between the two is that transmission planning occurs on a much larger scale, often across multiple utilities' service territories. MISO, with the collaboration of stakeholders, performs its MTEP analysis on its system annually. The MTEP model uses a 10-year planning horizon, with projects often approved to meet 5-year out system needs, allowing for new transmission solutions to be considered, approved, and constructed given extensive time requirements for new transmission siting.

Impact of Time Considerations on Data and Model Operations

As stated in the previous section, the time horizon for each planning process is selected for each individual model based on the specific planning process needs and has an impact on the data that is available for the model. Other timing considerations can also impact the costs, benefits, and system operations, and therefore may also impact overall process results. For example, inputs into the model, such as commodity price forecasts or technology cost forecasts, tend to become more uncertain as they are projected further into the future. This, in turn, increases the risk or uncertainty of the model results because the future is less defined. Depending on the type of analysis, physical limitations of the modeling software will effectively limit the functional time horizon. For instance, if an analysis is required using hourly load data, conducting this analysis over a 20-year time horizon becomes computationally intensive and any potential benefits to the analysis must be weighed against the additional costs and burden to perform this analysis. Understanding the impacts of the selected time horizon on both the input data available to the model and on the computing power and time required helps planners make the appropriate selection given the unique objectives and scope of each process.

Other timing considerations, such as the expected useful life, or measure life for certain resources such as EWR, can also have a significant impact on both the cost and resource mix selected by the model. When possible, it is important to perform the analysis of resource options in whichever planning process allows for the full valuation of the costs and benefits the resource provides. To ensure that all resources are given equitable treatment, this analysis can then be used to inform the other planning processes with different time considerations and ensure the input data provided is in alignment with the analysis results.

Forecast Granularity

As detailed in the previous section, differences in the objectives and scope of the system analyzed require differences in temporal considerations when developing each processes' forecast. The same is true when it comes to considerations of forecast granularity. The granularity (hourly, daily, monthly, yearly, etc.) of the forecasts used for load, demand, system peak, commodity prices, and technology adoption curves have a significant impact on the plan's costs and composition and must be properly selected to ensure an optimal plan. The proper level of forecast granularity is determined by both the function of the model, the processing time required by the model, and the granularity of the available source data.

The energy sector is currently undergoing a significant change in the technologies used to create electricity, the tools used to measure and track energy from source to end-use, and how the system utilizes this information to operate more effectively all need to adapt. As technologies and tools develop that allow for better control over when and how the system and its components operate, these advancements present opportunities for increased granularity in the data collected and available to develop planning forecasts. However, the increased role of non-traditional solutions, such as DERs or NWAs, in addressing the needs of the system require different planning techniques and tools to better understand and plan for their system impact. As opposed to more traditional generation resource options, which are valued on the capacity and energy provided, alternate solutions like DERs and NWAs often provide value through other services, such as ancillary services, grid support, or deferment of grid investments. Properly accounting for the value streams of non-traditional resources often requires more granular operating data that provides information about how these resources function and impact the grid on a more localized level. Without more granular data that can account for all the value streams of these non-traditional resources, they cannot be compared equitably to traditional resources to address a system need.

It is also important to have adequate visibility into how the system operates to understand points of constraint or other system reliability issues during times of peak demand. Traditional reliability metrics, such as planning reserve margin or loss of load expectation (LOLE), have been utilized for years by planners to ensure that the system is able to reliably meet load obligations throughout the entirety of the planning horizon, often considered on an annual peak basis. As the system shifts away from relying on a small number of high-capacity, base-load resources that are dispatched all hours available (as a “must run” offer), to a large number of intermittent resources whose dispatch is not directly controlled, these metrics may not provide the necessary level of detail to reflect the impact of this shift on system reliability. For instance, during the December 16, 2020 stakeholder meeting, MISO presented information on its MTEP process. It detailed that while this shift in system resources has not resulted in a significant change to aggregate system LOLE, it has shifted and compressed reliability risk to a smaller number of hours. This has resulted in increased risk in certain hours of the day. Without adequate granularity into system operations, this shift in risk along with other system trends may not be captured and therefore cannot be properly planned for.

One of the major limiting factors for allowing the equitable consideration of DERs and other non-traditional resources is the capability of the modeling software to accurately model the operations and value of these resources. As discussed during the December 16th stakeholder meeting, most of the capacity expansion software currently being used do not have access to the necessary data or are unable to properly model these resources. Instead, DERs and other non-traditional resource options are often embedded into the load forecasts; this prevents these resources from being considered against more traditional resource options and prevents any interactions between DERs or with other system resources from being captured.[28] As DER penetration in the system increases, the opportunity for utility cost savings through deferment of system maintenance or replacement is only fully realized by having a DER forecast that accounts for both the system impacts of DER currently installed and new DER resources, based on the best available data. Updating the modeling software and data used will allow for the level of granularity necessary to perform a full analysis of these resources, but improvements to the current process of embedding DER impacts into the load forecast can also be made. By leveraging the results of other planning processes, like the five-year distribution plans, planners can provide more detailed DER adoption and operations forecasts to other processes like IRPs. Although not equivalent to allowing the IRP to optimize its portfolio using DER and other resources, this does not require significant updates to the current IRP planning process while at the same time providing a more robust forecast of DER adoption.

Current Limitations and Determining Optimal Modeling Granularity

Like timing considerations discussed previously, the different planning processes considered in this report have different data granularity needs depending on the planning objectives and other factors, including scope of the system being analyzed. While oftentimes more detailed input data allows for the model to perform a more granular analysis, the use of this data is limited by current visibility into the system and/or the computational capabilities of the modeling software. Traditional capacity expansion models often require the aggregation of system cost and performance data into broader categories, such as 'typical weeks' or 'on-peak' and 'off-peak' designations, due to limitations with the models' capabilities. While newer modeling software can utilize more granular data, such as at hourly or sub-hourly time intervals, there are often functional limitations that prevent these data from being fully utilized in all planning processes where they apply. These limitations require an understanding of the value and cost of using more granular data when making forecast considerations.

Modeling the operations of a system heavily reliant on baseload, fossil-fueled generation resources is relatively simple; due to time and expense requirements to ramp up and ramp down these resources, they are often assumed to run non-stop when available. This allows for dispatch decisions to be made using less precise time intervals without adversely impacting the accuracy of the model. As intermittent and distributed resources make up a larger share of the system's energy supply, increasing the granularity of the time intervals used in the system model allows it to be more responsive to an evolving energy system. However, the benefits of using more granular time intervals in the model are only fully realized as the input data that is supplied to the model reflects an equivalent level of granularity. When considering appropriate time intervals for

[28] Tom Eckman, Lawrence Berkeley National Lab (2020, December). *Determining Utility System Value of Demand Flexibility From Grid-interactive Efficient Buildings,* p 89.

planning processes, the capabilities of the software and the granularity of the available input data help to inform the value of performing a more granular analysis.

In general, for processes which are longer-term in nature, such as IRPs, there are more limited use cases where increasing the model's granularity is both feasible and will provide value. Since IRPs in Michigan assess a company's energy and capacity position over a 15-year time horizon, it becomes computationally intensive to increase the granularity of the model. At the same time, the value of this increased granularity is limited to those time intervals where the model is deciding to either dispatch, retire, or add a new resource, and by the model's ability to consider all value streams of non-traditional and intermittent resources. For shorter-term planning processes like five-year distribution plans, increasing granularity can have a more significant impact on the results of the model. In the case of five-year distribution plans, the planning process seeks to analyze individual circuits to determine whether constraints or reliability issues exist during peak hours. Getting the most value out of this analysis requires insight into not only how individual resources operate at each time interval, but also how the system and individual circuits are operating at that same time. This granular visibility becomes even more critical as DERs and other customer-owned resources are connected to the circuit and these impacts become more varied across the system. This type of analysis has not been historically performed, as the requisite information has been unavailable or uncollected by the distribution planners. However, recent advancements in tools and techniques allow for this information to begin to be incorporated into the different planning processes.

Future Improvement Opportunities Using Nascent Approaches & Tools

Previous sections discussed both the need for and current limitations in incorporating more granular data, including input forecasts, into the different planning processes. Software and techniques used historically for system planning are rapidly becoming inadequate to model the system as it shifts away from traditional, base-load driven generation to include more DERs and other intermittent resources. While some of the software and other tools used for this planning have been updated or replaced by utilities, oftentimes these new tools are used in a way that limits their ability to model the system. The evolution of planning processes to accommodate the changing electric system presents opportunities for utilities to improve the input forecasts used, either by incorporating new tools and techniques, or by better utilizing existing data to inform these forecasts.

One way to improve the granularity of the model is to ensure that data used in modeling is the most detailed and up-to-date data available and applicable to the planning process. As the penetration of DERs and other customer-owned resources have increased, utilities have begun installing technologies, such as advanced metering infrastructure (AMI), that allow for greater visibility into individual customers' energy usage. Technologies like AMI provide utilities insight into how the system operates down to the circuit level and provide data that can be utilized in determining additional demand side management programs or control options that provide even greater load flexibility for planning. AMI data can be used to improve the forecasting process by providing a more detailed and granular look at the impacts of locational and temporal factors on the operation of existing DERs and NWAs, while also assessing locations that could benefit from the addition of DERs or NWAs to support the grid. Developing the capability to utilize this data to inform the utility's analysis and providing the results of this analysis to the public will not only improve the ability for customers and project developers to work with the utility to site new DERs but will also provide a better understanding of the potential to implement DERs and other NWAs on the system, while considering location differences inherent to the grid. Additional software and techniques to address the changing dynamics in these planning processes are regularly developed by both private and public research institutions, and some of the tools in development were discussed during the stakeholder meetings for this workgroup. Planners should continue to investigate the applicability of these different tools and techniques to the planning processes, as this workgroup continues to refine the IRP filing requirements and MIRPP in the future.

Transparency

In Michigan, each utility develops forecasts for their IRP that are tailored specifically to their individual service territory and developed independently of one another. Their methodology is complex, data intensive, and differs from one utility to the next due to their different business models, service territories, and customer profiles. Tailoring a scenario to a utility's specific need can often require combining different public or private forecasts to develop a more accurate methodology. Commonly used sources include U.S. Energy Information Administration (EIA), National Renewable Energy Laboratory (NREL), Lazard, Electric Power Research Institute, IHS Markit, Moody's Analytics, University of Michigan Economic Forecast, Itron, etc. It cannot be understated how critical accurate sources of data are for the planning process. A growing focus on implementing EWR, DR, and DERs (more specifically behind-the-meter generation), can further complicate forecasting in IRPs.

The three current scenarios in the IRP, as required by the MIRPP, are Business as Usual, Emerging Technologies, and Environmental Policy. These scenarios are developed by aligning technology costs, fuel price assumptions, environmental assumptions, and Michigan fleet retirement and addition assumptions, making it difficult to find a single, publicly available source that includes all these requirements.

There are strengths and weaknesses, based on different perspectives, to the use of private vs. public sources. From a regulatory perspective, a disadvantage to utilities using propriety resources is the inability for regulators and stakeholders to critically examine the assumptions, techniques, and results of the load forecast. Staff is also unable to replicate utility forecasts during the IRP review process due to the use of proprietary information. For utilities, the benefit of having the flexibility to assess all resources, public and private, is that they are then able to determine the most accurate forecast based on need and fit. A study conducted by Ernest Orlando of Lawrence Berkeley National Laboratory in 2016 analyzed forecasting methods for 12 Western U.S. utilities and found that "planners should consider supplementing third-party forecasts or conducting alternative economic forecasting to minimize forecasting error that can be attributed to outside parties."[29] Forecasts that are accurate are best for everyone; they prevent utilities from over or underspending and customers from overpaying.

In a December 16th, 2020 MI Power Grid Advanced Planning meeting, participating utilities were asked to provide feedback to questions asked by Staff. These requests included feedback on recommended publicly available data sources that should be used for capacity, energy, technology, and fuel price forecasts and any other collaborative ways to develop forecasts that could be used by all Michigan utilities filing an IRP. In this feedback, all utilities maintained that continuing with flexibility and stakeholder input will result in the most accurate forecasts. They argue that technology and fuel forecasts should be guided by the intent and purpose of the scenario in non-reference cases. Regarding energy price forecasts, there was a concern that no publicly available sources for energy price incorporate the specific MIRPP requirements: technology costs, fuel price assumptions, environmental assumptions, Michigan fleet retirement, and additional assumptions. Capacity prices will be different for each utility and thus utilities do not feel using a publicly available capacity price forecast will be of value (if one even exists). Another point where all utilities agree is that it is important that, no matter what source is being utilized, the most recent data available is used.

In the feedback, some utilities mentioned sources that they currently use but none have recommendations for publicly available sources for capacity, energy, technology, or fuel price forecasts. There is a concern that an over-reliance on a single source, private or public, could lead to forecasting errors that over-estimate load growth. If Staff were to recommend public sources that increased transparency but resulted in over-reliance, it could result in an inaccurate forecast with economic, reliability, and resiliency concerns.

The largest value of limiting the data available for utility forecasts to public sources would be in providing consistency and transparency. However, if this results in a less accurate forecast, this would be a disservice to the process. The varying filing dates of IRPs from each utility also provides another challenge to recommending specific sources with the risk of inconsistent data as these sources are updated over time. Michigan is not alone in entrusting the utility will produce accurate forecasts for modeling. California is the only state in the U.S. whose public utilities code explicitly states that forecasting models be validated.

Staff agrees that increased stakeholder collaboration on forecasting methodology provides a level of transparency that is beneficial to the IRP process by bringing together voices that offer diverse perspectives and a broader understanding. A challenge common with both transmission-level and distribution-level modeling is, as Brady Cowiestoll pointed out during the December 16, 2020 meeting, very few models are public and thus cannot receive stakeholder feedback. Some public

---

[29] Ernest Orlando Lawrence Berkeley National Laboratory. (2016, October). *Load Forecasting in Electric Utility Integrated Resource Planning,* p. 48. https://eta-publications.lbl.gov/sites/default/files/lbnl-1006395.pdf.

sources that Staff recommends the Commission require is using NREL for technology costs and EIA for price forecasting. Since it is in the utility's best interest to provide an accurate forecast for energy and capacity procurement, there is some level of self-regulation via economic consequence present for all parties involved. Given that we have multijurisdictional utilities in Michigan, suggesting a Michigan only technology forecast for all utilities' IRP development is not recommended. Therefore, Staff finds a prescriptive approach on what data sources are used would serve as a limiting measure rather than one that promotes necessary flexibility and advanced development.

Staff Recommendations and Conclusions

Forecast Components

Utilities should take a component or modular approach to forecasting. Key components should include:

- Gross demand and energy forecast;
- Gross load shape;
- Load shapes for EWR, DR, and other load modifying resources that are not being modeled as resources. Examples could include already implemented EWR or EWR achieved outside of utility EWR programs;
- EV adoption and charging profiles; and
- Behind-the-meter resources and DER forecasts that include customer owned photo-voltaic and storage.

Utilizing this approach allows for a clearer understanding of various components impacts on net load forecast. It also allows adjustment of specific forecast components (while leaving others unchanged) for certain scenario, sensitivity, or risk analysis efforts. When applicable, system level forecast components should maintain consistency across planning processes. Deviations should be explained within utility filings.

Forecast Consistency

Forecast Alignment/Coordination across resource, distribution, and transmission planning efforts. Clear relationship (handshake or link) between forecasts used in one planning effort to those used in subsequent efforts. Base forecasts should include consistent assumptions and drivers. Scenarios might alter these assumptions and/or drivers to generate separate load forecasts for certain scenario analyses. Scenarios should be based on consistent and reasonably aligned assumptions. If applicable, scenarios evaluating the same future across different plans should also have consistent assumptions and drivers.

Other relevant utility functions (MPSC power supply cost recovery, MISO capacity costs) should also be consistent with planning forecasts when applicable. Staff recognizes that a forecast is a snapshot in time, and it will change in the future. As forecasts change, utilities should provide clear details on how the forecast has changed as well as an explanation on why the forecast has changed. This should be done from one case to the next, always referencing back to the most recent, previously filed case forecast vs. the current filing in question. This provides a traceable relationship from one planning process and one case to another throughout the many that are filed with the Commission.

When possible, input forecasts should provide the necessary level of granularity to capture all value and cost streams of the resources being considered in the planning process. Depending on the specific planning process considered and due to limitations in available data and computational capacity, some input forecasts may not be adequately developed in specific processes. In this instance, utilities should take every effort to utilize the appropriate input forecasts from other planning processes which are able to develop these forecasts using the necessary level of detail, adjusted to allow for use in the current planning process.

External Transparency

Provide visibility into forecasting process so that stakeholders can understand utility's forecasting process (and be convinced all the above is occurring). Encourage use of publicly available data sources but allow utilities flexibility to use data available to them to generate the most accurate forecast for each process. Staff also encourages utilities to consider granting access to forecasting data, to the extent that it does not violate licensing or subscription agreements, to stakeholders to improve their understanding of inputs and assumptions and to provide a more comprehensive analysis for all parties involved. It is important to maintain transparency and consistency without being overly prescriptive because accuracy is important, and a one size fits all approach may not work best for all utilities.

Staff and stakeholders should have visibility into forecasting methodology and changes/evolution of forecasts from one plan to the next (for example, from IRP to subsequent IRP or from IRP to transmission planning to distribution planning to IRP). The most current forecast should be supported by the underlying data and assumptions. Inconsistencies with those underlying assumptions and data that significantly change forecast results from one process to the next should be identified and justified in a narrative manner. Forecasts should be synchronized or reconciled from process to process. Understanding that different processes and utility functions call for forecasts with different time horizons and granularity. Relationships, where they exist or why they do not, should be clear.

To increase forecasting alignment between distribution plans and IRPs, utilities should include the following in distribution plans:

- Assessment of historical forecast accuracy using statistical measures such as mean absolute percentage error.
- Distribution planning efforts should consider resource needs identified in resource planning. Resource planning includes formal integrated resource plan filings but also the continual process of resource planning used by utilities between formal IRPs.
- Use scenario analysis within distribution plans (using scenarios aligned with IRP scenarios).
- Improved stakeholder communication (distribution plan technical conferences with stakeholders prior to filings).

- Align assumptions between planning processes:
    - DERs
    - NWAs
    - EVs
    - Electrification

Transmission

Background

Relevant Transmission Orders

The passage of PA 341 initiated the current IRP regime and requirements that transmission options be assessed when considering capacity expansion.[30] In addition, PA 341 modified existing Certificate of Need requirements. These requirements included a mandate to analyze transmission options.[31] The Commission last updated the Certificate of Need filing requirements on May 11, 2017. These requirements state that such a filing must consider transmission interconnection costs and include any transmission interconnection study or required transmission modification to interconnect the facility.[32]

DTE Electric was the first utility to file under the new Certificate of Need requirements. Some stakeholders thought that DTE's filing in Case No. U-18419 should be evaluated under the new IRP law and IRP filing requirements. The Commission disagreed, stating that the filing was made before the updated IRP filing requirements were finalized.[33] Nevertheless, the Commission did comment on the transmission analysis put forward by DTE Electric in Case No. U-18419, finding it unnecessarily weak. It ordered the subsequent DTE Electric IRP to be filed under the updated requirements, have a more robust transmission analysis, and that the company should work more closely with TOs to explore transmission solutions.[34] During the course of Case No. U-18419, the Commission finalized the filling requirements for IRPs filed under MCL 406.6(t) in Case No. U-15896. The filing requirements have an entire section dedicated to transmission, Section XII.

Consumers Energy was the first utility to file an IRP under MCL 460.6(t) with its associated filing requirements. The Consumers Energy IRP ultimately ended in a settlement, so the Commission did not extensively address the IRP's transmission portion. The Commission did, however, briefly touch on expectations for Consumers Energy's next IRP, stating that:

---

[30] MCL460.6t, Section 5,(h) and (j).
[31] MCL460.6s, Section 4(d) and Section 11(g).
[32] Commission Order in Case No. U-15896, May 11, 2017, pp. 16,19.
[33] Commission Order in Case No. U-18419, April 27, 2018, pp. 8-13.
[34] Id at pp. 111, 115-116.

> *Looking ahead to Consumers' filing of its next IRP in 2021, the Commission expects that Consumers will work in close collaboration with METC {Michigan Electric Transmission Company] and will provide METC a thorough and timely retirement analysis of its aging generation units and new resource plans to allow for a more accurate and in-depth analysis of transmission issues in the next IRP.*[35]

While this does not place new requirements on Consumers Energy, it does signal that the Commission expects greater collaboration and communication in future IRPs.

The Commission provided its most detailed commentary on a utility's effort to fulfill the transmission filing requirements in its order in DTE Electric's IRP, Case No. U-20471. Even though the Commission found the IRP's transmission analysis complied with the letter of the law, it found that it did not comply with the spirit of the language or the language from the previous Certificate of Need Order regarding transmission analysis. The Commission required DTE Electric to coordinate with ITC Transmission to evaluate options for increasing import or export capacity as well as to evaluate transmission options that can facilitate power purchase agreements of energy and/or capacity from neighboring planning zones or RTOs.[36]

The Commission also commented on transmission planning in the IRP filing for Upper Peninsula Power Company (UPPCo) in Case No. U-20350. The Commission did not order UPPCo to conduct another U.P. transmission study when considering UPPCo's proposed reciprocating internal combustion engine, primarily due to two recent in-depth MISO studies. The Commission did, however, emphasize the need to study the near-term operation effects on long term resource planning decisions.[37]

It is clear from all that the Commission has said in the first round of IRPs that it is not satisfied with the content or completeness of the transmission analyses presented. To that end, Staff worked with the MI Power Grid Advanced Planning Workgroup to inquire about transmission possibilities and alignment in the IRP before updates to the IRP filing requirements are developed in Phase III of Advanced Planning.

Overview of Transmission Planning in Michigan

Transmission planning in Michigan is carried out by the seven investor-owned, municipal, and cooperative transmission-owning utilities operating in the State[38] in conjunction with the relevant RTO. Michigan is part of two different RTOs, MISO and PJM. These organizations are responsible

[35] Commission Order in Case No. U-20165, June 7, 2019, p. 90.
[36] Commission Order in Case No. U-20471, March 19, 2019, pp. 82-83.
[37] Commission Order in Case No. U-20350, December 16, 2019, p. 47.
[38] International Transmission Company (ITC), Michigan Electric Transmission Company (METC), American Transmission Company (ATC), Wolverine Power Supply Cooperative (Wolverine), Xcel Energy, American Electric Power's (AEP) Indiana Michigan Power (I&M), and Michigan Public Power Agency (MPPA).

for operating the transmission system and wholesale electricity markets, dispatching generation, ensuring reliability, and planning the Bulk Electric System over large geographic areas. In addition to planning transmission systems to ensure reliability during the most severe conditions and scenarios, RTOs also plan transmission to enable state and federal policies and ensure that long-term changes in the resource mix and customer demand can be reliably managed.

TOs commence their annual planning process by using internal planning models to identify various issues on their systems and designing projects to address those issues. MISO has an 18-month process, while PJM's requires 24 months. In this "local" transmission planning phase, TOs develop projects to address local reliability, North American Electric Reliability Corporation (NERC) reliability criteria, customer load growth, economics, generator interconnections, and asset age and condition, among other objectives. The local transmission plans developed by the TOs are incorporated into the RTOs' regional planning cycles as possible transmission solutions for inclusion in the annual MISO MTEP or PJM RTEP.

In collaboration with stakeholders, the RTOs' regional planning processes first involve building region-wide reliability planning models to test the transmission system for possible NERC or TO-specific criteria violations such as overloads, single or multiple contingencies, and to evaluate the overall impact of TOs' transmission plans. Throughout their respective planning cycles, the RTOs hold regular, public stakeholder meetings to solicit input and answer questions on proposed transmission plans. The RTO planners will evaluate potentially cost saving or more efficient transmission upgrades and may recommend an alternative solution to a TO submitted plan. The RTO planners may recommend a project for approval as proposed, with modifications; may find that a project is not needed based on their own regional planning evaluation; or that the transmission issue is resolved with a non-transmission alternative (NTA). The planning models are available to stakeholders who provide security assurances per the RTOs' tariffs and Business Practice Manuals.

Eventually, the RTO will recommend a final suite of projects to stakeholders and the Board of Directors for approval in their annual MTEP or RTEP report.[39] If a project is approved by the RTO's Board in the annual report, the sponsoring TO is under an obligation to construct the project. However, RTOs continuously monitor the progress of approved projects within the context of new system conditions or stakeholder feedback and may withdraw an approved project should they find it to be no longer needed.

[39] PJM's "Supplemental Projects" are incorporated into the RTEP but are not PJM Board approved. Supplemental projects are driven by equipment condition performance and risk, operational flexibility and efficiency, resilience, customer service, and drivers not meeting any other project category.

Figure 1: MISO Typical MTEP Cycle

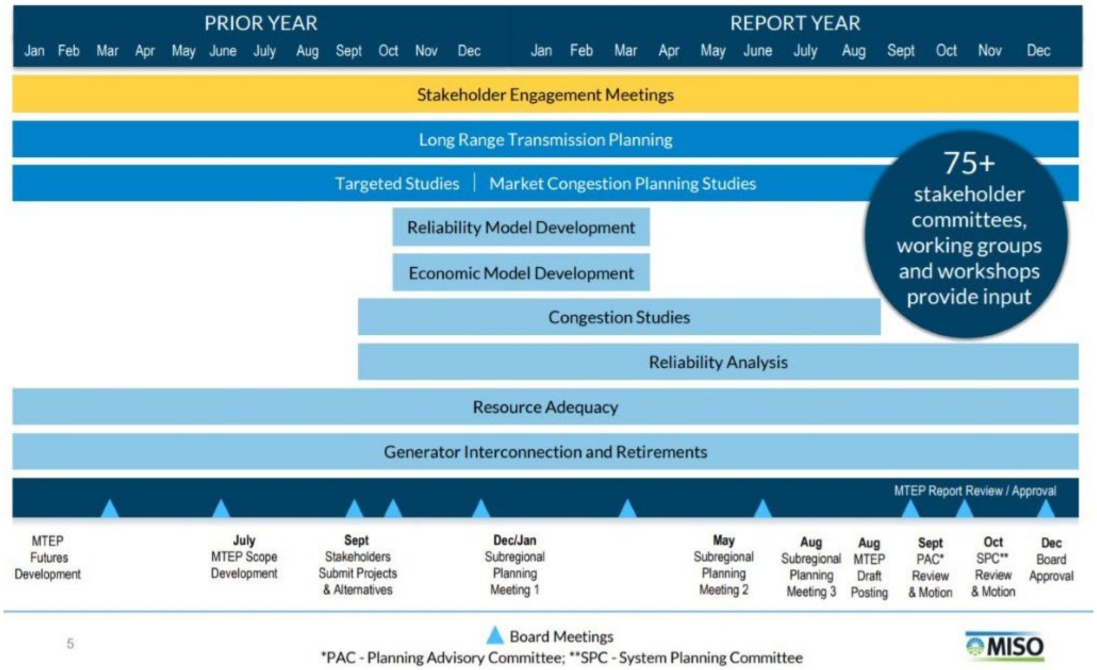


Figure 1 illustrates a typical MISO MTEP planning cycle. The RTOs conduct additional "top-down" planning to evaluate regional and interregional transmission drivers, including baseline reliability, economic efficiencies, long-range issues, and to enable public policy requirements. Outside of the formal expansion planning cycles, the RTOs may also conduct targeted studies to examine specific circumstances or policy studies to provide insight into emerging issues on the Bulk Electric System.

In addition to the transmission planning processes, RTOs also facilitate generation interconnection processes. Unlike the transmission planning processes, interconnection processes can take considerably more time to identify and execute due to the complexity and variability of potential interconnection requests. These different and distinct processes add another layer of complexity to transmission planning.

RTO's Role in Ensuring Resource Adequacy

Beyond transmission planning responsibilities, operating the transmission system, and wholesale electricity markets, MISO and PJM each have constructs in place to support load serving entities (LSEs) in meeting their peak demand into the future, commonly referred to as "resource adequacy." Each do this by providing a wholesale market to purchase and sell electricity capacity in addition to the energy and ancillary services markets. In Michigan, resource adequacy is assured through the IRP and annual capacity demonstration processes, which incorporate aspects of the RTOs' regional constructs.[40] While the plans to ensure resource adequacy and authorize where

[40] MCL 460.6t, Section 8.

and what types of resources are constructed is under state jurisdiction, the RTOs' capacity constructs are designed to support in-state processes like the IRP and provide flexibility and guidance to LSEs.

PJM's construct provides for a competitive auction, the Base Residual Auction (BRA), to procure capacity resources three-years in advance of the delivery year, with annual Incremental Auctions conducted each year after the BRA until the delivery year, which begins on June 1 and ends on May 31. MISO's construct provides for a single auction, the Planning Reserve Auction (PRA), that is held in April prior to the delivery year that also begins on June 1 and ends on May 31.[41] Both RTOs' constructs allow for self-scheduling, where an LSE commits a unit as a capacity resource by offering it into the auction at a price of zero, bilateral contracting, or allowing an LSE to demonstrate that it has enough capacity to meet its peak demand requirements by submitting a plan to the RTO-- referred to as a Fixed Resource Requirement (FRR) Capacity Plan in PJM or a Fixed Resource Adequacy Plan (FRAP) in MISO. Resources that clear in the BRA or PRA are obligated to provide capacity for the entire delivery year, and LSEs that serve load are obligated to pay those resources the auction clearing price in the Locational Deliverability Area (LDA – PJM) or Local Resource Zone (LRZ – MISO) where the resources are located. The details of both RTOs' embedded modeling assumptions, how resources are accredited capacity value, and determinations of how many resources are needed in a particular LDA or LRZ are continuously being refined through their respective stakeholder processes with the approval of the Federal Energy Regulatory Commission (FERC).

I&M, in the Southwest corner of the Lower Peninsula, is the sole Michigan LSE that is a member of PJM. The Company assures it has the capacity it needs to meet its peak load by submitting an FRR Capacity Plan to PJM. The other LSEs in Michigan are a part of the MISO footprint and pursue a mix of self-scheduling resources, purchases through the PRA, and bilateral contracts or FRAPs. Some LSEs in neighboring northern Indiana and every LSE in Ohio are members of PJM, whose footprint extends throughout the Northeast. The boundary between RTOs is referred to as a seam.

The existence of lengthy seams within and surrounding the southern portion of Michigan and to the east with Ontario's Independent Electricity System Operator, as well as Michigan's unique peninsular geography, present certain challenges for planning transmission to ensure resource adequacy requirements are met. The RTOs themselves are also facing challenges in ensuring resource adequacy as the bulk electric system becomes less reliant on traditional base-load power plants and more reliant on intermittent generation resources and resources connected to the distribution system, in addition to increasing severe weather events brought about by the changing global climate.

[41] MISO is currently evaluating moving to a seasonal resource adequacy construct in its stakeholder process, whereby the RTO would conduct multiple concurrent auctions for multiple seasons.

Resource Adequacy Evaluations in MISO

NERC standards require that RTOs calculate the amount of capacity resources that are needed on the system that exceed peak customer demand such that the expected number of events where demand is not served occur only one day in ten years, or 0.1 LOLE days per year[42] – a metric used throughout North America to measure resource adequacy. NERC provides flexibility for how individual RTOs apply the LOLE metric with respect to the type and severity of events considered for LOLE. In MISO, for example, a LOLE event is one requiring firm load shed after all operating reserves and DR have been deployed.

Using the LOLE metric, MISO calculates a region-wide planning reserve margin (PRM) sufficient to cover planned transmission maintenance outages, forced or generation outages, deratings of generation and DR resources, reasonably anticipated variations in weather, and uncertainty in load forecasts. Using forecasted coincident peak demands, Planning Reserve Margin Requirements (PRMRs) are calculated for each LSE and for the LRZ, which represent the total capacity obligations required for the planning year. LSEs must produce or procure Zonal Resource Credits (ZRCs) or prove they have them in a fixed resource adequacy plan (FRAP), bilateral contract, or self-scheduled supply to meet their PRMR. MISO's construct also imposes a Local Resource Requirement (LRR) on each LRZ, which is the amount of ZRCs required to be procured in the zone to achieve the 0.1 LOLE per day requirement at peak demand without contributions from resources outside the LRZ.[43]

The ability to transfer capacity resource credits into or out of an LRZ, Capacity Import Limits (CILs) or Capacity Export Limits (CELs), are determined by MISO pursuant to a transfer analysis study. For example, MISO will determine the maximum CIL into an LRZ by modeling decreasing generation within the LRZ under study and increasing the generation in adjacent MISO LRZs, while adjusting for exports to non-MISO loads. The CIL and CEL determine the amount of ZRCs that can be imported/exported for purposes of meeting resource adequacy obligations. The LRR reduced by the CIL results in a Local Clearing Requirement (LCR), the amount of ZRCs that must be procured from resources physically located within the LRZ. In cases where an insufficient amount of ZRCs are available from within an LRZ to meet the LCR, the PRA will clear all ZRC offers in the LRZ at the Cost of New Entry (CONE) – a FERC-approved price for capacity to reflect the cost of bringing a new natural gas combined cycle plant in the zone online and to incentivize the construction of new generation resources within the LRZ.[44] All of these MISO studies and calculations are conducted annually and therefore subject to change. Therefore, there is an inherent risk associated with the MISO resource adequacy construct.

---

[42] NERC Standard BAL-502-RF-03.

[43] LRZ 7 had CONE price of $257.53/MW-day in Planning Year 2020-2021.

[44] Midcontinent Independent System Operator Business Practice Manual, BPM-011.

MISO's Michigan Capacity Import and Export Limit Study

On November 7, 2019, the MPSC sent a letter to MISO Chief Executive Officer John Bear formally requesting MISO perform a study that "augment[s] [its] LRZ 7 Out-Year CIL-CEL Study Scope," to not only consider changes to the CIL and CEL from generation fleet changes, but also additional ways to increase these limits. The request was developed in part based on the results of the Commission's Statewide Energy Assessment (SEA)[45] delivered to Governor Whitmer, which included a recommendation that "Utilities…and stakeholders, should further investigate opportunities to expand Michigan's capability to import additional electricity to address short- and long-term reliability and resource adequacy needs in a more holistic manner as Michigan experiences additional power plant retirements."[46] MISO and MPSC Staff coordinated on the development of an initial scoping document for the study, which was then further developed and refined throughout a stakeholder process.

MISO presented the initial draft scoping document for the Michigan CIL/CEL study to stakeholders in February 2020 and solicited feedback on its proposed study scenarios. Based on the desired outcomes given in the Commission's formal request letter, MISO developed three scenarios that examine the cumulative impact of the changing generation resource mix on the CIL. Scenario 1 is a five-year outlook that examines the impacts and necessary measures to increase the local CIL by 500 MW and 1500 MW increments. Scenario 2 is a 10+-year outlook that examines the impacts and necessary measures to increase the regional CIL by 3000+ MW. Scenario 3 is a 15+-year outlook that examines a potential future with high renewable penetration: incremental renewable resources added in scenario 2 are assumed to have doubled nameplate capacities. Data on future generation resource retirements and additions were included based on the utility's planned resource additions and retirements that resulted from their most recently approved IRPs, while Scenario 3 also modeled resource additions and retirements outside of LRZ 7 based on the MTEP20 'Accelerated Fleet Change' future.[47]

MISO conducts the analysis by incorporating planned resource additions and retirements into its model; it then increases generation outside of LRZ 7, while simultaneously decreasing generation inside of LRZ 7 to determine the amount of power that can be transferred into the zone before a reliability constraint is identified. MISO finalized its scoping documents after incorporating updated resource information provided by stakeholders and began to perform its analysis based on the priorities identified. MISO provided updates on the progress of the analysis, including initial results and alternate solutions proposed by stakeholders, at various public stakeholder meetings held throughout 2020.

---

[45] Statewide Energy Assessment (SEA) Final Report issued in Case No. U-20464 (September 11, 2019).
[46] SEA, Recommendation E-8.2.
[47] March 13, 2020 MISO CIL scoping doc, p. 8.

During the May 19, 2020 Michigan Technical Study Task Force, MISO provided its initial results for its Scenario 1 analysis, which met the Commission's desired import limits, with one of the voltage analyses identifying two potential transmission solutions to address constraints and meet the desired import capability. MISO provided its next update on its analysis at the group's September 18, 2020 meeting, which included updated Scenario 1 and initial Scenario 2 results. Scenario 1 was updated from the prior meeting to include a new voltage analysis methodology; this resulted in no constraints being identified to achieve the desired import capability. The Scenario 2 analysis resulted in achieving the desired import capability, after including two topology upgrade projects. At the end of this stakeholder presentation, MISO provided an opportunity for stakeholders to submit alternate projects to those identified in the analysis to address system constraints; these proposals were to be incorporated into the analysis and presented at the next meeting.

At the November 17, 2020 meeting, MISO provided the results for Scenario 2 that incorporated the alternate projects proposed by DTE Energy and LS Power. Four total projects were proposed, all of which met the target import capability. Cost estimates were provided for all but one of these projects, which allowed for comparison with the original system upgrade project included in the analysis. During the group's February 12, 2021 meeting, MISO presented interim analysis results for the final time, including an update on Scenario 3 assumptions based on stakeholder feedback. Scenario 3 results showed the targeted CIL being achieved after including an upgrade project. The meeting also provided a venue for stakeholders to propose alternate project solutions to be considered as part of a future Scenario 3 analysis.

MISO completed the CIL/CEL analysis in April 2021. The analysis found that in additional to an ITC/METC rebuild project, three alternative projects submitted by DTE Energy also exceeded the Scenario 3 CIL target of 6,200 MWs. The initial results of this study have helped to illustrate the impact of various renewable penetration levels in the future on the CIL for LRZ 7. The Michigan Capacity Import/Export Limit Expansion Study Draft Report is available on MISO's website.[48]

FERC Orders 841 and 2222

In 2018, FERC issued landmark Order No. 841 ordering RTOs to remove barriers that prevent electric storage resources (ESRs) from participating in their respective capacity, energy, and ancillary service markets. Recognizing the diverse capabilities of ESRs, FERC required that the RTO participation models allow a resource to provide all capacity, energy, and ancillary services that it is technically capable of providing, can be dispatched by the market operator, and can set wholesale market clearing prices as both a seller and buyer in the market.

---

[48] Michigan Capacity Import/Export Limit Expansion Study Draft Report, https://cdn.misoenergy.org/20210429%20MTSTF%20MI%20CIL-CEL%20Item%2002%20Draft%20Study%20Report545312.docx, retrieved April 29, 2021.

New wholesale market opportunities, along with decreasing costs of ESRs at both customer and utility scales, could incentivize significant growth in ESRs connected to the transmission system. In addition to capitalizing on wholesale electricity market opportunities, the level of renewable generation investments that will be necessary for Michigan to be carbon neutral by 2050 will likely require substantial investments in ESRs simply to preserve reliability. Whether for market or reliability reasons, ESR deployments are expected to significantly increase over time, with long term implications for both transmission and resource investment decisions.

The level and extent to which ESRs proliferate, with opportunities to participate in wholesale energy markets, retail pricing regimes, or serve a transmission or distribution system need, is unknown but could potentially require upgrades on both the distribution and transmission systems to facilitate more dynamic system operations. ESRs may ultimately perform a transmission function, a market function, or obviate the need for a traditional energy resource, and the potential impacts to Michigan’s overall electricity system could be significant. Performing comparative analyses of ESRs that may address similar issues, are planned as an NTA, or against other resource types, may add additional complexity to integrated resource planning.

In September 2020, FERC issued another landmark ruling, Order No. 2222, to promote competition in wholesale electricity markets by requiring RTOs to remove any barriers in their tariffs that prevent DERs, or DER aggregations, of at least 100 kW from competing in their capacity, energy, and ancillary service markets and put them on a level playing field with other resources. DERs are defined as small-scale power generation, storage technologies, or demand side resources located on a utility’s distribution system, a subsystem of the distribution system, or behind a customer’s meter. The rule allows several DERs to aggregate together to participate in the RTOs’ markets, allowing those resources that participate in a retail program to also participate in wholesale markets.[49]

Developing a new participation model for aggregated DERs will be a complex undertaking for the RTOs, state regulators, and stakeholders. Initial Order 2222 compliance discussions are underway; however, it is expected to take until at least 2022 for RTO tariffs to be developed and filed with FERC. Much like ESRs, it is difficult to predict where and in what quantity DERs may proliferate because of Order 2222’s required wholesale market opportunities. Also, much like ESRs, DERs could eventually add additional complexity to resource planning. For example, growth in DERs might drive the need for additional transmission investment to deliver distributed capacity or might obviate the need for a generation or transmission investment altogether.

[49] State Regulatory Authorities have authority to determine whether it is appropriate to allow DER or DER aggregations to participate in both retail programs and wholesale markets and can continue to prohibit DER aggregators from bidding DR into wholesale markets.

Discussion

Enhanced Communication

In addition to geographic constraints that limit the ability to access and count on resources from outside of LRZ 7, Michigan's utility business structure adds layer of complexity to electric system planning. Transmission facilities are owned and planned by TOs that are separate from generation resource owners, who may be regulated electric generation and distribution utilities, municipal and cooperative utilities, or an Independent Power Producer (IPP). This utility business structure in Michigan results in a transmission planning process that is separate from resource and distribution planning. Adding further complexity to the planning process, Michigan allows for 10% retail choice, where 10% of Michigan's electricity demand is served by alternative energy suppliers (AESs).

During the January 19, 2021 MI Power Grid Meeting, several expert speakers and stakeholders reinforced the need for direct communication at regular intervals throughout the IRP process.[50] Stakeholders acknowledged that the purpose of regular communication is to facilitate a bi-directional and iterative flow of information. For effective transmission modeling and planning, MISO noted the importance of facilitating a flow of information from the TO to the regulated utility *and vice versa.*[51] The current MTEP and RTEP processes allow for some transfer of information; however, those are largely focused on specific transmission system needs, generation and load interconnections, and energy market constraints. These processes may not take a holistic look at Michigan's electric grid or promote a bi-directional flow of information between regulated utilities and TOs in ways that identify long-term resource and distribution needs or ways in which the transmission system can support future changes that are likely to occur on the distribution system and in utility resource portfolios.

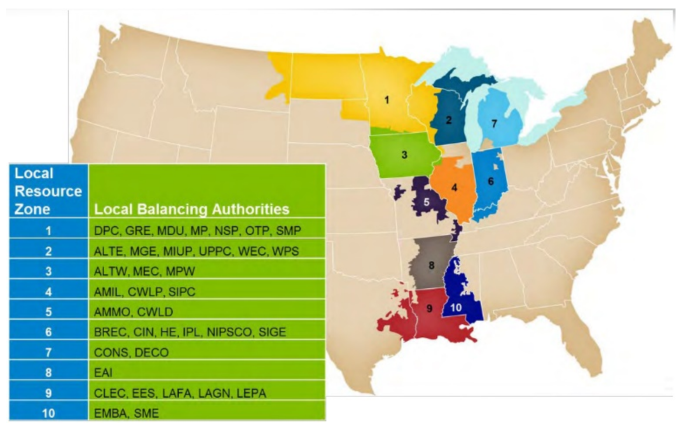
To facilitate a bi-directional flow of information between Michigan's regulated and transmission utilities, Staff recommends that a formal process for regular engagement be established. Staff understands that there is communication between TOs and regulated utilities currently, and that formalizing and documenting this process creates both transparency for stakeholders and ensures that key topics are discussed. Staff recommends that regulated utilities coordinate with TOs to schedule a biannual meeting to discuss the regulated utility's emerging or expected distribution system needs and generation resource fleet changes and how the transmission system may best support those changes, including potential transmission investment. This discussion should expand beyond the typical MTEP discussion of load interconnections and transmission system needs to include granular discussion of distribution and transmission system operational needs such that holistic solutions for operational concerns that provide the most value to ratepayers can

[50] Advanced Planning Stakeholder Meeting, January 19, 2021.
[51] Advanced Planning Stakeholder Meeting, January 19, 2021.

take place. This process is needed to help bridge the coordination gaps in generation/transmission/distribution planning processes created by Michigan's utility business structure and help improve the overall alignment in system planning processes. Finally, all interested stakeholders are encouraged to participate in the IRP dockets at the MPSC, as well as in the transmission planning meetings held by MISO and PJM.

Opportunities and Challenges of Importing Capacity into MISO Local Resource Zones 2 and 7

It has been identified by stakeholders that a greater ability for LSEs in LRZ 7 to access the wider MISO market for capacity and energy resources could potentially provide an opportunity to lower both capacity costs for Michigan ratepayers and in-state air emissions, in addition to providing for increased system reliability. The level of renewable energy resources that will be needed to meet Governor Whitmer's goal of carbon neutrality by 2050[52] will be substantial. While a significant amount of renewable energy resources will need to be constructed within LRZ 7 to meet resource adequacy requirements, there may be opportunities with respect to importing capacity or increasing the CIL. Solutions sets that are tested and vetted that can cost effectively satisfy these needs and contribute to resource adequacy should be considered in the IRP. Relying on imports from PJM or the Ontario, however, is generally incompatible with resource adequacy requirements without assurances that the capacity will be deliverable to LRZ 7 when dispatched by MISO.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

However, as previously noted, certain conditions in Michigan, and LRZ 7 in particular, make relying on imported capacity challenging relative to other states in MISO or PJM. Peninsular geography, a lengthy MISO-PJM seam, international borders, and limited transmission ties to adjacent LRZs in MISO together result in restrictive in-zone generation requirements to meet the LCR. Furthermore, expected increases in wind and solar generation are likely to increase the LRR, potentially diminishing the value of generation outside of LRZ 7 in future years.

In recent years, a low CIL has required nearly all capacity resources to be procured within LRZ 7. In the 2020-2021 planning auction, there were insufficient resources in LRZ 7 to meet the LCR,

[52] Executive Directive No. 2020 – 10 aims to achieve 28% reduction below 2005 levels in greenhouse gas emissions and economy-wide carbon neutrality no later than 2050.

causing the price for capacity to clear a CONE price of $257.53/MW-day, versus $4.75-$6.88/MW-day in the rest of the MISO footprint. A higher CIL into LRZ 7 would allow for greater utilization of resources external to LRZ 7 and increase the likelihood that there are sufficient resources within LRZ 7 to meet the LCR, assuming all other inputs to the LCR calculation remain unchanged.

The MISO Michigan CIL/CEL study demonstrated that the LRZ 7 CIL in future scenarios is highly sensitive to generation resource citing decisions and modeling methodologies and assumptions. With ongoing refinements to MISO's and PJM's resource adequacy constructs and the continued enhancements to resource adequacy and reliability over the long term, modeling assumptions and methods could have a significant impact on the projected benefits of a particular transmission project meant to utilize or increase the CIL and decrease the LCR. If transmission or distribution projects meant to facilitate imports were relied on for resource adequacy, LSEs and their customers would face a risk that the LCR might later increase due to unforeseen factors and out-of-zone resources would no longer be available for meeting the PRMR. Further, ratepayers could risk paying for a transmission project meant to relieve a binding import constraint only for another binding constraint to appear elsewhere in the system or under future system conditions, resulting in similar import limitations. Together, these issues represent a significant challenge to incorporating imported capacity resources into IRPs.

These challenges, while significant, are not insurmountable. Inclusive participation by stakeholders in both the MISO and PJM transmission planning forums and in Michigan's IRP processes could bring about innovative solutions to benefit ratepayers. Greater participation by stakeholders in these forums is encouraged. LSEs should continue to consider viable and tested transmission solution sets in the IRP process. And opportunities for enhanced communication and information sharing should be pursued.

Stakeholders seeking further information or refinements to the resource adequacy construct that drives the limiting of CIL and LCR values for LRZ 7 are encouraged to participate in MISO's public Resource Adequacy Subcommittee and Loss of Load Expectation Working Group stakeholder forums.

Stakeholder Feedback and the Role for Transmission in IRPs

Current law[53] requires that utility IRPs include "(a)n analysis of potential new or upgraded electric transmission options for the electric utility" and "(p)lans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements." However, from prior IRP cases,[54] it

[53] MCL 460.6t.
[54] Commission Orders in Case Nos. U-20165, U-20351, and U-20471.

has become clear that the transmission analysis requirements are overly broad and additional specific requirements would increase quality and transparency of the analysis.

During the January 19, 2021 MI Power Grid meeting, Staff requested written stakeholder feedback on questions pertaining to what changes should be made to IRP transmission analysis requirements and how transmission constraints, such as the CIL and CEL, should be modeled in future analyses. Stakeholder responses made diverse suggestions for improving future IRP transmission analyses; however, support for enhanced communications and transparency requirements emerged as a consistent theme across the comments. Information asymmetries, system visibility, and analysis lead times and documentation were mentioned as current challenges in the process.

Stakeholders suggested a variety of potential filing requirements meant to mitigate these challenges. Further aligning the IRP process with regional transmission planning processes at MISO and PJM would potentially improve information asymmetries and modeling input assumptions and provide for a more regional and long-term view of the transmission system. Stakeholders also suggested that the Commission further define what types of transmission analysis should be required in the IRP, including suggestions for reliability evaluations of utility PCA and analysis of the best locations for generation relative to existing and planned transmission.

Stakeholder comments differed more substantially in how energy and capacity availability outside of LRZ 7 should be modeled in IRPs and the requirements that should be imposed on out-of-state resources that respond to an request for proposal. Comments ranged from fully utilizing MISO resources external to LRZ 7 irrespective of CIL and CEL values or other changes to the RTO resource adequacy construct, to accounting for lost energy revenues associated with imports, to leaving the consideration of external resources entirely up to the filing utility. Regarding modeling transmission import and export constraints in an IRP, stakeholders offered a variety of comments reflecting the limits of CIL/CEL values. This included volatility, lack of and uncertainty of out-year data, and that the CIL/CEL value reflects a snapshot under specific system conditions and does not reflect day-to-day energy transfer limits.

This feedback from stakeholders has identified several ways in which transmission planning can be a more direct component of an IRP analysis, and it was helpful to Staff in both considering the overall role of transmission planning in IRPs and the development of Staff's recommendations for process improvements outlined below. Additionally, future IRPs are expected to incorporate increasing amounts of distributed generation, energy storage resources, and new technologies implemented at generation, transmission, distribution, and end-use levels of the electricity system. Staff expects that specific IRP transmission analysis needs and assumptions will continue to evolve, so filing requirements should ensure adequate flexibility to incorporate new analyses amid changing system conditions.

Recommendations for Potential Filing Requirements Update in Phase 3

Although the IRP Filing Requirements are not expected to be updated until the Commission issues an order at the next phase of the MI Power Grid, Staff identified several preliminary recommendations to improve the Transmission Analysis Filing Requirements.[55] Staff and stakeholders will continue to discuss any recommendations and Commission guidance that may be provided during Phase 3 for the Advanced Planning workgroup, which is expected to take place in late 2021 and extend through the third quarter of 2022.

The IRP Filing Requirements established in Case No. U-18461 and U-15896 identify specific information that a utility shall include in its IRP filing.[56] The discussion and written feedback from the January 19th MI Power Grid meeting provided useful insight about information that stakeholders find valuable in understanding the transmission analysis that a utility conducts in accordance with MCL 460.6t(5)(h), which states that an IRP shall include "[a]n analysis of potential new or upgraded electric transmission options for the electric utility."

Staff noted that several stakeholders desire more clarity about how the utility has engaged local transmission owners. Given Michigan's utility business structure, this is a crucial step in the planning process because it provides a link between the transmission planning process and the resource planning process. The current IRP Filing Requirements, Section XII(b), direct the utility to file "[a] detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in effort to inform the IRP process and assumptions including a summary of meetings that have taken place.[6] The description included in recent IRP filings has been relatively high level. Engagement has also varied from utility to utility. Experts suggest communication happen early in the process and at regular intervals to allow for full engagement and to facilitate sufficient information flow between the TO and filing utility. Therefore, Staff recommends requiring a utility to engage a TO a defined minimum number of months prior to filing, allowing for possible extensions if agreed to by the regulated utility and the TO. Staff recommends that meeting minutes be provided along with pertinent details about utility requests for studies, discussions about assumptions and any conclusions made during the meetings, alternatives that were reviewed, and any other pertinent information that can be made public or provided through typical contested case confidentiality agreements.

The current IRP Filing Requirements, Section XII(e), direct a utility to file "[a]ny information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP".[57] Staff continues to believe that information provided by the TO relating to import and export capability, transmission system

---

[55] December 20, 2017 Commission Order, Case No. U-15896, *Exhibit A. IRP Filing Requirements,* p. 4.
[56] Id.
[57] Id.

efficiency impacts, and advanced technology affecting supply- or demand-side resources are important to include with IRPs. To give the Commission, Staff, and stakeholders a more complete view into the impact the transmission analysis has on the utility's proposed course of action, Staff recommends that regulated utilities request additional information from the TO and/or RTO for inclusion an IRP if made available, allowing TOs a reasonable amount of time to complete a thorough analysis. Relevant information includes: (1) identification of system locations or regions where energy resources are able to interconnect to the transmission system with minimal transmission investment, (2) identification of system locations or regions where generation resources could address future transmission system reliability issues, and (3) recent studies that indicate ways in which the CIL/CEL can be increased or may change and the resulting impacts to the LCR.

The Staff appreciates that grid infrastructure information can be highly confidential, and that the information provided would likely be subject to confidentiality agreements. The details that can be provided in some studies and reports may also be limited if it is determined that the information is critical energy infrastructure information. Stakeholders should also have reasonable expectations about the details that are able to be provided in an integrated resource plan case. As discussed earlier in this section, stakeholders are encouraged to engage in the MISO and PJM regional transmission planning processes directly if they are interested in more detailed transmission-level planning information.

Staff Recommendations and Conclusion

The Staff believes the following recommendations will foster greater collaboration and transparency in the IRP process that reflects Michigan's unique independent transmission utility business structure.

Enhanced Communications

To facilitate enhanced information sharing and communication between Michigan's regulated utilities and transmission owners, Staff recommends that a transparent process for regular discussion of Michigan's current and future system needs be established. Staff recommends that regulated utilities and transmission owners coordinate to schedule a formal biannual meeting to discuss the regulated utility's emerging or expected distribution system needs and generation resource fleet changes and how the transmission system may best support those changes, including potential transmission investment. The Staff recognize that some regulated utilities regularly meet and collaborate with TOs in meetings to discuss needs on the distribution system or emerging generation issues, and that such meetings can result in transmission projects. However, the Staff observe that there is inconsistency across utilities and a lack of transparency in this process, and that the proposed formalized process would ensure that necessary collaborations do occur early in the IRP development process and with a regular frequency.

The Staff recognize a need for a holistic and collaborative discussion of generation, transmission, and distribution systems, potential long-term solutions to long-term system needs, and potential alternatives in a bidirectional format with regulated utilities and TOs. These meetings will help bridge the coordination gaps in generation/transmission/distribution planning processes created by Michigan's utility business structure and improve the overall alignment of the state's electric system planning processes. Staff recommends that regulated utilities and TOs, come to an agreed upon meeting schedule and timeline for performing transmission analyses, providing feedback, and evaluating alternatives.

Informed Transparency

Staff recommends that the Commission consider revising its IRP filing requirements to require that regulated utilities request the relevant TO provide a transmission analysis that should inform its resource decisions and be included in the IRP filing materials. Staff recommends that the transmission studies that regulated utilities request from that the relevant TO should:

(1) Utilize the most recent relevant RTO reliability planning models that have been finalized in an MTEP or RTEP process at the time of IRP development.
(2) Evaluate the reliability considerations of the utility's proposed course of action, recognizing refinements may be made by the time an IRP is filed.
(3) Evaluate the reliability, cost, and resource diversity benefits of TO proposed transmission alternatives.[58]

Additional analysis that regulated utilities should include with IRP filing materials if provided by the TO or RTO should include:

(1) Studies that identify system locations or regions where new resources can interconnect to the transmission system with minimal transmission investment.
(2) Studies that identify system locations or regions where generation resources could address future transmission system reliability issues.
(3) Studies that identify and estimate the cost of upgrades that would increase the local CIL/CEL and impacts to the LCR.

Staff recommends that the Commission consider requiring that all studies that support a utility's proposed course of action and the transmission or alternatives analysis be provided to the extent possible. All requests for transmission studies and information should be documented by the regulated utility and included in IRP materials.

Stakeholder Participation

Staff encourages all interested stakeholders to participate in the MPSC's IRP cases, as well as in MISO and PJM's transmission planning meetings to the extent practical. For process efficiency, stakeholders with similar interests, or desiring similar outcomes, are encouraged to align where

[58] This process will not replace, replicate, or pre-determine RTO planning process. All proposed transmission projects must go through regular RTO transmission planning processes for project evaluation and approval.

possible. Inclusive participation by stakeholders in the MPSC's IRP process and in MISO's and PJM's transmission planning forums could bring about innovative solutions to benefit ratepayers and the environment. Viable and tested transmission solution sets from any stakeholders should continue to be considered by LSEs in the IRP process. Stakeholders seeking further information or refinements to the resource adequacy construct that drives the CIL and LCR values for LRZ 7 are encouraged to participate in MISO's public Resource Adequacy Subcommittee and Loss of Load Expectation Working Group stakeholder forums.

Value of Generation Diversity

Background

Generation diversity has come under additional public attention recently, as utility resource portfolios evolve through the retirement of traditional fossil-fueled generation and the addition of distributed renewable resources. Extreme weather events, such as the one that caused outages throughout Texas in February 2021, are becoming more common as climate change continues to destabilize global weather patterns.[59] These issues increase scrutiny into the role that generation diversity plays in ensuring demand is reliably met at all hours of the day. Although the focus of these debates is often centered on the performance of one specific technology or another, the main concern of most customers is maintaining system reliability and providing resilience during extreme events. While adequate generation diversity can play a key role in ensuring system integrity, it is one of multiple factors and must be properly understood to ensure it is quantified and valued in a way that both supports system reliability and resiliency while optimizing cost and non-cost factors.

The Commission is required by statute to consider diversity of generation supply when determining whether an IRP is the most reasonable and prudent means of meeting energy and capacity needs.[60] The language in the statute does not prescribe specific methods for valuing generation diversity. Additionally, the Statewide Energy Assessment report (SEA) recommended "that the value of diversity in power supplies be quantified as part of future integrated resource plans filed by electric utilities."[61] On February 2, 2021, Staff held a stakeholder session focused on understanding the value generation diversity provides and methodologies for quantifying those benefits.

---

[59] Kovacs, Thomas and Barrett, Kimberly, "Michigan Climate Assessment 2019: Considering Michigan's Future in a Changing Climate" (2020). Michigan Climate Assessment. https://commons.emich.edu/michigan_climate2019/1/.
[60] MCL 460.6t(8)(a).
[61] Statewide Energy Assessment Report, September 11, 2019, p. iii.

Conceptually, the value of generation diversity derives from mitigation of risk. Technological advances, electrification, and climate change, on top of the inherent complexity of forecasting, mean that future conditions are difficult to predict. As a result, a resource plan optimized solely for one potential future is likely to face significant challenges if the future does not play out as predicted. If too much reliance is placed on one fuel or generation technology, such as a disruption that affects that fuel's availability or that technology's ability to function properly, would adversely impact a utility's ability to meet demand. An overly homogenous resource portfolio also brings economic risk, as the utility will be unable to shift away from that resource if it becomes uneconomical compared to other technologies or fuels. A diverse generation portfolio also benefits from the distinct characteristics and ancillary services each technology provides.

As discussed below, while different metrics have been developed to directly quantify the diversity of a generation portfolio, there is no one agreed upon metric to quantify generation diversity. These indices provide a useful empirical metric to support valuing generation diversity but are insufficient on their own to recommend adoption as a prescriptive valuation tool. Generation diversity must not only be quantified, but also have its value properly accounted for in order for it to be useful in system planning. Generation diversity is not a prescriptive property to be blindly sought after; it is a natural consequence of risk analysis and how changing variables impact model forecasting inputs and the resulting ability for a resource plan to serve load. As such, a more robust risk assessment will more accurately value and promote a resource portfolio's diversity.

Discussion

Current state of diversity in Michigan's electric system

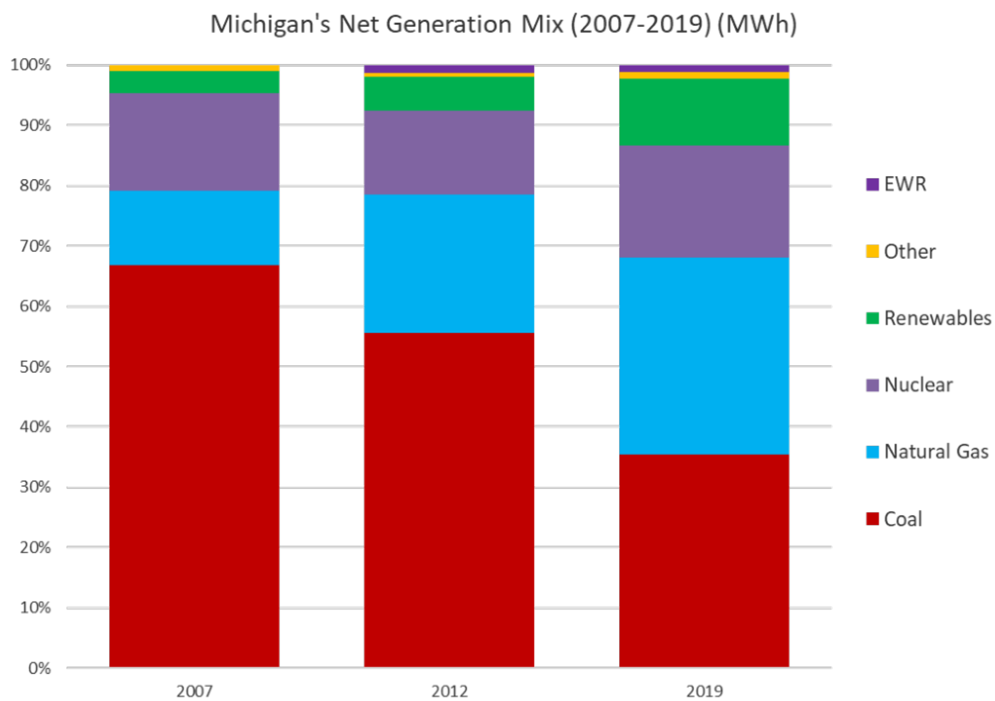
To properly assess and value generation diversity, it is important to establish a working definition for what diversity means. From an academic perspective, diversity is defined by three main components: variety, or the number of categories; balance, or how evenly dispersed these category populations are; and disparity, or how different the categories are from one another.[62] When relating this broader definition to generation diversity specifically, diversity in generation is often measured in terms of fuel source as this allows both the variety and balance of generation to be considered, while different fuel and generation characteristics relate to disparity.[63] When considering the generation diversity of a resource portfolio, differences in fuel source and operating technology are often the key metrics. Resource operational characteristics, in addition to fuel type, can be used to further distinguish between technologies that use common fuel sources (i.e., distributed utility-owned solar vs. centralized utility-owned transmission interconnected solar).

---

[62] Stirling, Andy. 2007 *A general framework for analyzing diversity in science, technology and society. J. R. Soc. Interface.* **4:** 707-719. https://royalsocietypublishing.org/doi/pdf/10.1098/rsif.2007.0213.
[63] Id.

As the transition from traditional fossil-fueled generation to clean, distributed resources has accelerated in recent years, Michigan's overall generation portfolio changed as well:

Figure 2: Historical Energy Production in Michigan (2007-2019), MWH

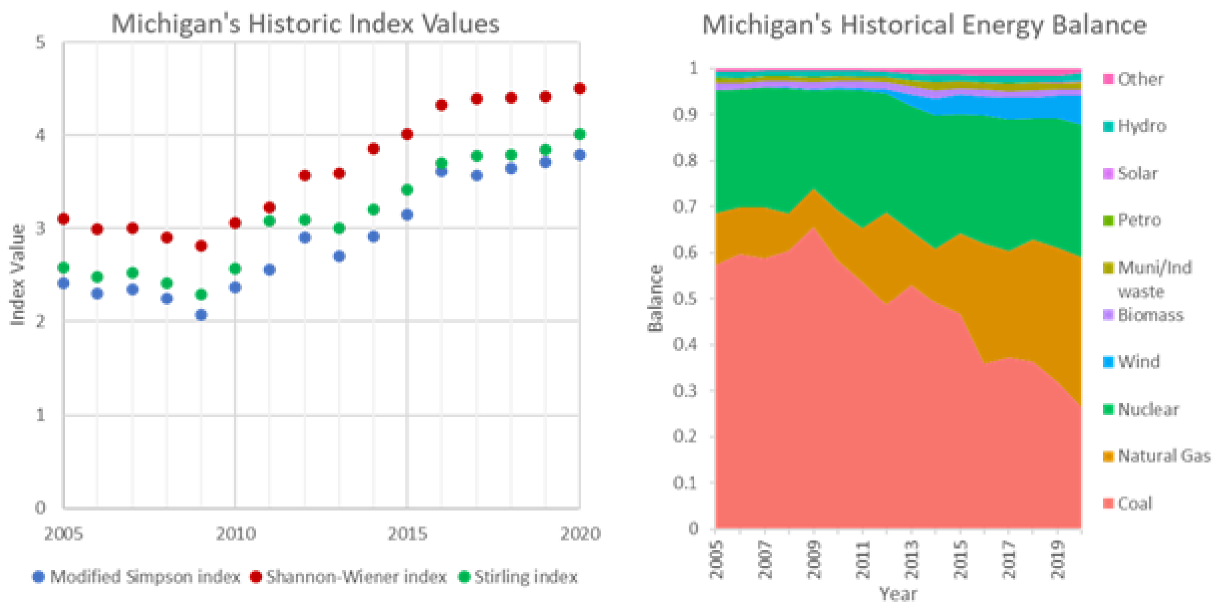


Looking at Michigan's changing energy mix in Figure 2, it illustrates that system diversity has increased significantly over time, as cleaner technologies become more widely adopted and generation retirements result in coal being a smaller share of the State's capacity and energy supply. However, simply looking at such data alone does not directly account for the three components of diversity: variety, balance, and disparity. Diversity indices have been formulated to better quantify and value these individual components; the studies referenced in this report calculated diversity using three well-established indices: Stirling, Shannon-Wiener, and Simpson.[64]

[64] Refer to Appendix E of this report for a detailed explanation of each of these diversity indices.

When analyzing the State's generation diversity over time using these indices, there is a more modest increase:

Figure 3: Generation Diversity in Michigan Over Time, Using Shannon-Weiner, Simpson, Stirling Indices[65]



These indices consider additional factors not captured by simply looking at the overall generation mix of a system on its face. Additionally, while each of these indices followed a similar trend over time, year-to-year variations and overall magnitude of change differ between each, as these indices weigh the three components of diversity differently. It is vital to understand how these different indices value, and therefore quantify, generation diversity if it is to be considered quantitatively in utility planning. A discussion of these three indices and their differences is provided in Appendix E.

The value of generation diversity in the electric system

While generation diversity has a well-established definition, assessing the value of diversity in a generation portfolio is a more nuanced task. The value assigned to generation diversity in planning processes should account for the value it provides to the electric system and could be identified in any number of planning processes, including distribution, transmission, and resource planning. Utility planning processes seek to provide an optimized resource portfolio that balances overall system costs with desired levels of reliability and resiliency. Put another way, the utility planning processes seek to provide an optimized portfolio that balances overall system costs with

---

[65] Yue-wei Wu, Tiffany, Rai, Varun, "Quantifying Diversity of Electricity Generation in the U.S." White Paper UTEI/2017-02-1, 2017. http://energy.utexas.edu/the-full-cost-of-electricity-fce/.

an acceptable level of risk. Therefore, generation diversity should be valued for its potential to provide cost savings or improve system reliability and resiliency. Cost savings are currently considered when making resource decisions in system planning models; resource solutions are evaluated against one another to determine the option that provides the greatest system value. While diversity of a resource portfolio can impact overall portfolio costs, the value of generation diversity can be more directly accounted for through risk avoidance. To fully consider how a portfolio's generation diversity contributes to risk avoidance, it is helpful to understand the potential for increased risks that may result from a lack of generation diversity in the system. This section will focus on how generation diversity impacts system risk through exposure to commodity price volatility and interdependency with other economic sectors, and the impact of locational and operational considerations on the potential to either address or create the need for new capital investments in the electric system.

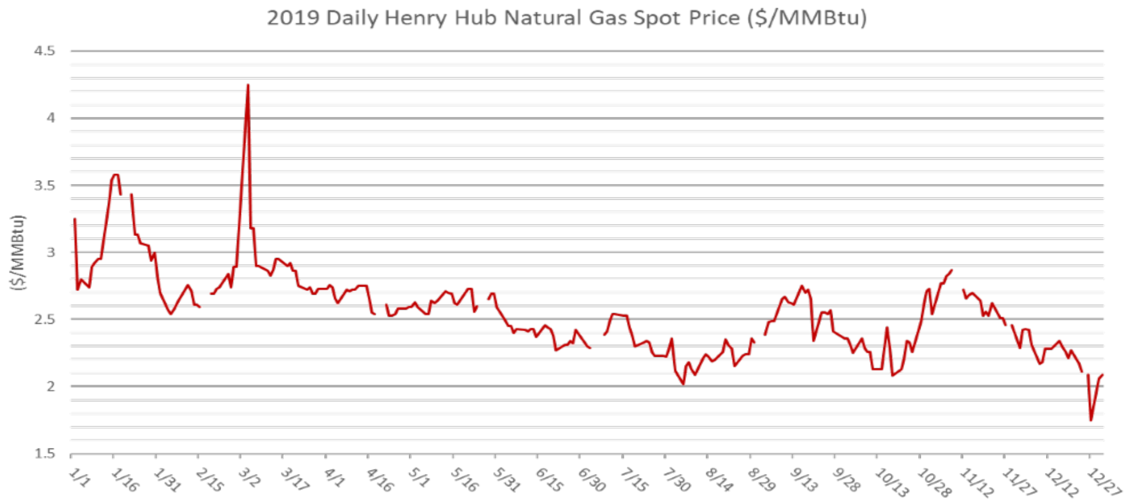
Natural gas has become a dominant fuel source for Michigan generating units, and is expected to overtake coal to become the largest single source of energy in the State's resource mix by 2025.[66] At the same time, natural gas is still used as the primary heating fuel for 75% of Michigan residents.[67] Due to this interdependency, ensuring natural gas supply for electricity generation can be difficult during the heating season, particularly in times of adverse weather when heating loads are highest and supply chains may be impacted. This was the case in the January 2019 Polar Vortex when an incident at critical natural gas infrastructure during times of extreme cold weather caused natural gas supply concerns in the State. Through the coordination of utilities, emergency services, and State government officials, a request was made for Michigan residents to reduce their heating load to avoid service shutoffs. While fuel supply issues are often exacerbated by extreme weather, there are price volatility risks even under normal conditions. Natural gas supply and demand have historically varied due to a wide range of domestic and international issues, corresponding to significant fluctuations in natural gas prices over relatively short periods of time. Utilities mitigate some of this risk by entering long-term contracts with suppliers for a consistent amount of fuel to operate their units during normal conditions. However, when demand for natural gas generation exceeds the utility's supply reserves, it is exposed to market price volatility to procure the necessary gas supply through spot market purchases.

Figure 4 demonstrates the daily historical price volatility inherent in natural gas spot prices. One of the risks of a lack of generation diversity is it can increase the reliance on one fuel source, thereby increasing the utility's risk of requiring spot purchases from the commodity market during unfavorable market conditions to meet load requirements.

---

[66] 2020 MPSC Annual Report, p. 31.
[67] SEA, p. 18.

Figure 4: Daily Henry Hub Natural Gas Spot Prices for 2019[68]



The transition from an energy system dominated by large, centrally located, fossil-fueled generation resources to a more distributed and carbon-neutral system has broad implications for how the system will be operated and perform in the future to meet demand. As this transition accelerates, the locational and operational characteristics of generating resources must be valued, when assessing diversity, to ensure that the planned solutions are optimized to provide the most value for the least cost. In the past, locational considerations for the siting of new thermal generation resources did not have an impact on generation performance; therefore, resources were located near load centers to reduce energy transport costs and losses. As the fuel sources used by intermittent resources like solar and wind are naturally dependent on location, siting of these resources at the utility-scale is often focused on locations of high generating potential or adequate space for the installation. This may result in large-scale renewable resources being sited at locations distant from the load they serve, which requires robust transmission and distribution (T&D) system as support. The displacement of centrally located fossil-fuel generation by distributed renewable resources places additional stress on the T&D system it has to handle the flow of electricity from more injection points spread throughout the grid.

This results in increased siting analysis to identify points of failure and potential necessary investments in the T&D system to support new resources. Distributed Energy Resources (DERs) may not place the same burden on the T&D system, as these resources are by nature dispersed over the utility's service territory. Additionally, while siting DERs at one location may increase stress on the system, at another location it may alleviate stress and the necessity for future T&D investment. Generation diversity metrics need to value not only differences *in* technology types, but also differences *among* technology types which are otherwise not captured, such as

[68] https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm. Retrieved March 10, 2021.

operational characteristics. Additionally, generation diversity metrics should account for the value of locational characteristics, such as the potential to add to line congestion or provide system support.

The Role of Risk Analysis in Quantifying and Valuing Generation Diversity

Risk analyses, whether deterministic or stochastic, seek to evaluate resource portfolios against a variety of potential futures to determine the impact of these futures on system characteristics, often on a revenue requirement or other cost-based basis. In a deterministic model, the output is determined by initial conditions and parameter values specified by the user.[69] Deterministic modeling in a resource plan involves the use of scenarios and sensitivities, or specific futures that account for changes in either one variable (sensitivities) or multiple variables (scenarios) in modeling. A deterministic risk assessment can also be performed by testing the optimized resource portfolios resulting from one scenario and sensitivity combination (future) in other futures to determine its impacts on the optimized portfolio's performance. Stochastic analyses involve some inherent randomness in the input values assigned, and therefore test the system solution against a wide range of random futures not fully determined by the modeler.[70] Stochastic risk assessments utilize probabilistic distributions to introduce randomness into the system by varying one or more input parameters around an "expected value." Parameters can also be linked, allowing the impact of multiple parameters to be tested together. The result of this analysis is a comparison of the selected portfolio among a wide range of potential future conditions, without requiring user input to determine the specific parameter values in each future. More information about deterministic and stochastic modeling is available in Appendix D.

Currently, utilities are required to perform a risk assessment as part of the IRP process. The MIRPP requires specific scenarios and sensitivities be modeled in the IRP, in addition to any scenarios and sensitivities the utility has created. The IRP Filing Requirements specify this risk assessment should involve "analysis of the preferred plan and the optimal plans for each of the scenarios specified in the [MIRPP], as well as all additional scenarios and sensitivities filed with the IRP application."[71] The IRP Filing Requirements expanded the details of the required risk assessment, providing multiple approved analysis techniques,"[A]cceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent-based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation."[72]

---

[69] Deterministic vs. Stochastic Models, http://www4.stat.ncsu.edu/~gross/BIO560%20webpage/slides/Jan102013.pdf. Retrieved March 2, 2021.

[70] Id.

[71] December 20, 2017 Commission Order, Case No. U-15896, *Exhibit A. IRP Filing Requirements,* p 4.

[72] *Id.,* at p. 5.

For the initial IRP filings under MCL 460.6t, utilities used two risk assessment methodologies to test utility resource plans. Scenario analysis that involves analyzing the cost of optimized plans under other scenarios and sensitivities, and stochastic optimization through Monte Carlo simulations that involves utilizing probabilistic distributions and random samplings of variables to test optimized solutions. In general, utilities performed at least a scenario and sensitivity analysis on the required MIRPP scenarios and any additional optimized runs. Most utilities incorporated stochastic optimization into this assessment by using a Monte Carlo simulation to provide random samplings of select variables of interest.

Use of stochastic analyses allows for otherwise deterministic scenarios and sensitivities to be evaluated against not only the futures specified in each scenario and sensitivity combination, but also against futures not specified by the utility. Use of stochastic analyses provides a more robust analysis and reduces the potential for user bias to influence model parameters. Staff recommends that the Commission require utilities supplement the scenario and sensitivities analysis specified in the MIRPP by including a stochastic risk assessment for all required scenario optimized plans and any additional plans developed by the company. Utilities should report the results of this analysis, including all underlying data, and utilize visual aids, such as box and whisker plots or efficient frontier plots, to help convey this information. Examples of a box and whisker plot and an efficient frontier plot can be found in Appendix B and Appendix C. Staff recognizes the potential benefit of using deterministic analyses to evaluate plans against select well-defined modeling futures. Companies should provide support for their use of deterministic risk assessments as the most reasonable risk assessment methodology for each plan in which it was used.

Components of Diversity

As mentioned above, there are three main components that any study where diversity is consider: variety, balance, and disparity.[73] Variety is the number of distinct categories in the system, such as the number of different species in an ecosystem, and is the simplest measure of diversity.[74] For generation diversity studies, variety categories are most often either fuel or generation technology.[75] When categorizing by generation technology, fuel is also considered because the generation technology is specific to the fuel type. The categories considered can be somewhat subjective. For example, one study might consider distributed-scale solar as a different category from utility-scale solar, while another study might combine them.

Balance, the second component of diversity, is how evenly distributed the categories are. A system with a large variety of categories that is heavily weighted toward a single category will not be as

[73] Sterling, A., (2010) Multicriteria diversity analysis: A novel heuristic framework for appraising energy portfolios.

[74] Id.

[75] Wu, T. Y., Varun, R. (2017). Quantifying Diversity of Electricity Generation in the U.S. *Model Documentation and Results for ERCOT Scenarios*.

diverse of a system that has the populations of those categories more evenly distributed. The simplest assessment of balance is the proportionality of each of the categories, which is a positive fraction of the categories that sum to one.[76]

The final component of diversity is disparity, how different or distinguishable the categories are from one another. This requires looking at aspects and characteristics of the various categories and determining how far away from one another the categories are. While it may not be expressly quantified when looking at variety and balance, it is considered qualitatively when the different categories are being defined. Professional judgement is used to determine what the categories should be and what goes into the categories. This professional judgement is based on disparity. While there is some subjectivity in deciding what the categories will be, disparity when quantified is more subjective because decisions must be made about disparity using the intrinsic properties of the populations. A decision must be made about how dissimilar different categories are from one another based on those intrinsic properties. In addition, there may be disagreement about how different two categories are, or the weighting various intrinsic properties should receive.[77]

Diversity Indices and Limitations

Stirling, Shannon-Wiener, and Simpson indices are all sensitive to threshold effects. This means that the elimination of a category (fuel and/or generation type) can have an outsized effect on the various diversity indices. This should give us pause. If we value diversity incorrectly, we may end up in a situation where a certain type of generation or generation fuel will persist, even when it is otherwise uneconomical, on its value to diversity alone. For this reason, it is unwise to pursue diversity for diversity's sake. Rather, we should look at the benefits of diversity, which are largely a reduction of risk.[78] With that being said, there still may be value to certain generation types or fuel sources if they hedge against specific risks, particularly if these risks are of high impact.

Another reason that it may be unwise to pursue diversity for diversity's sake is that these indices do not directly consider other generation attributes, such as generator inertia, ramp rate, minimum up time, etc. They do not consider whether the population of generators in a system can run the system effectively or at all. Utility planning processes seek to provide solutions that allow the system to reliably operate in a cost-effective manner. While generation diversity can impact cost and reliability, it is one of many factors that must be considered. For this reason,

---

[76] Sterling, A., (2010). Multicriteria diversity analysis: A novel heuristic framework for appraising energy portfolios.

[77] Brazilian, Morgan. And Fabian Roques, Analytical Methods for Energy Diversity and Security: A tribute to Shimon Awerbuch. 1st ed., Elsevier, 2008, p. 10.

[78] Brazilian, Morgan. And Fabian Roques, Analytical Methods for Energy Diversity and Security: A tribute to Shimon Awerbuch. 1st ed., Elsevier, 2008, p. xxi.

generation diversity should not be considered in isolation, but should be considered as merely an aspect of the generation system.

Often generation diversity is talked about in the context of resiliency. It may be tempting to imagine that diversity is a direct path to resiliency. While diversity does hedge against risks, it is not equal to resiliency. Resiliency has aspects related to the transmission and distribution system that generation diversity does not consider. However, that is not to say that diversity does not have any effect on resiliency. It does in the reduction of risk that it provides.

Projections of Michigan’s Generation Diversity

As a first step when considering quantifying Michigan’s generation diversity, Staff projected Michigan’s generation diversity through 2030. Staff took five- and ten-year snapshots of Michigan’s generation portfolio and applied the various indices.

Staff used the net annual generation data from EIA’s Form-923 as the starting point for the calculation of the diversity indices. Staff used the disparity coefficients present in Wu and Varun to calculate the Stirling index (the disparity coefficients from this paper are presented as Figure 5).

Figure 5: Disparity Coefficients Presented in Wu and Varun for Selected Fuels.

	Coal	NG	Petro	Nuclear	Hydro	Geothermal	Solar/PV	Wind	Biomass	Muni/Ind Waste	Other
Coal	NA	0.171	0.171	0.126	0.271	0.271	0.271	0.271	0.088	0.271	0.1355
NG	0.171	NA	0.059	0.171	0.271	0.271	0.271	0.271	0.171	0.271	0.1355
Petro	0.171	0.059	NA	0.171	0.271	0.271	0.271	0.271	0.171	0.271	0.1355
Nuclear	0.126	0.171	0.171	NA	0.271	0.271	0.271	0.271	0.126	0.271	0.1355
Hydro	0.271	0.271	0.271	0.271	NA	0.199	0.199	0.077	0.271	0.128	0.1355
Geothermal	0.271	0.271	0.271	0.271	0.199	NA	0.123	0.199	0.271	0.199	0.1355
Solar/PV	0.271	0.271	0.271	0.271	0.199	0.123	NA	0.199	0.271	0.199	0.1355
Wind	0.271	0.271	0.271	0.271	0.077	0.199	0.199	NA	0.271	0.128	0.1355
Biomass	0.088	0.171	0.171	0.126	0.271	0.271	0.271	0.271	NA	0.271	0.1355
Muni/Ind Waste	0.271	0.271	0.271	0.271	0.128	0.199	0.199	0.128	0.271	NA	0.1355
Other	0.1355	0.1355	0.1355	0.1355	0.1355	0.1355	0.1355	0.1355	0.1355	0.1355	NA

For this reason, the EIA AER fuel codes had to be combined to match the fuel types considered in disparity coefficients. This resulted in distillate petroleum, residual petroleum, and waste oil AER fuel codes being consolidated into the Petro category. Staff consolidated other renewables and wood and wood waste AER codes into the Biofuel category. Pet coke and municipal waste and landfill gas AER codes were consolidated into the Industrial and Municipal/Industrial Waste category. The AER code for other and other gases AER code were consolidated into the Other category for the diversity calculation. The EIA did have net generation from storage. The net generation was negative and using a negative number in some of the equations produces spurious results. For this reason, storage was excluded.

Staff then calculated proportions for each of these categories and, from there, the indices for historical years. Staff used the modified Simpson index instead of the traditional Simpson index, as the modified version increases with increasing diversity. Staff also multiplied the Stirling index by a coefficient of 30 so the Stirling index would have the same order of magnitude as the other indices. These modifications of indices were identical to those performed by Wu and Varun.[79]

For projected years, Staff added planned units from approved IRPs and capacity demonstrations and removed generating units planned to be retired. Since this was assessed on an energy basis, the expected units were multiplied by a technology-specific capacity factor that was given by the NREL ATB.[80] While this methodology allowed Staff to project general diversity trends, a study that involves simulated dispatch of the units would likely yield more accurate results.

The analysis shows that Michigan's diversity will increase in the coming years under all diversity indices, as shown in Figure 6.

Figure 6: Michigan's Energy Diversity Over Time

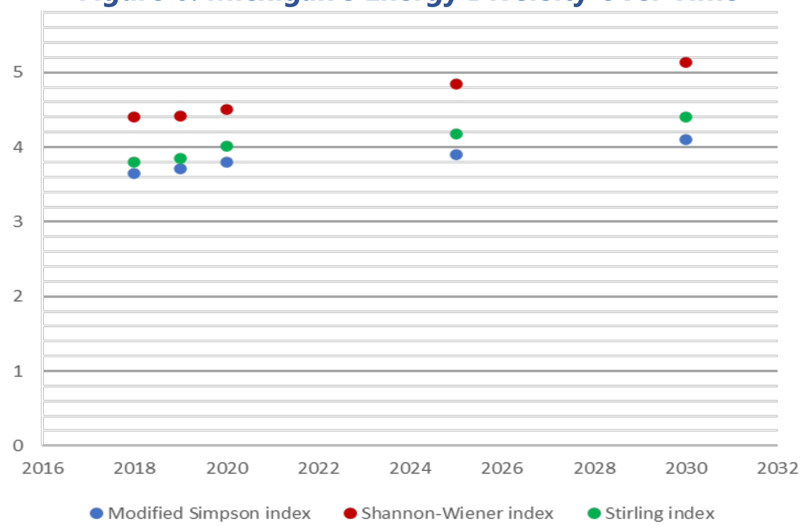


Figure 6 Illustrates the Modified Simpson index, Shannon-Wiener index, and Stirling index for Michigan's generation fleet on a historical and going forward basis through 2030. Each of the indices is a non-dimensional number.

The Shannon-Wiener index consistently stays above the other indices. This is largely because this index places a greater emphasis on "rare species," so small contributors are given relatively greater weight. In addition, Staff observed that the Stirling index is very close to the modified Simpson index historically. As time goes on, these indices begin to diverge. This means that not only is the balance of the system increasing, but the resources that are being added to replace coal when it retires have greater disparity with the rest of the existing system than the retiring coal units. While we may have a trend of increasing diversity for the foreseeable future, it is not guaranteed to continue. As more coal generation retires, there may come a point where diversity begins to

---

[79] Wu, T. Y., Varun, R. (2017). Quantifying Diversity of Electricity Generation in the U.S. *Model Documentation and Results for ERCOT Scenarios*.

[80] https://atb.nrel.gov/electricity/2019/summary.html, https://atb.nrel.gov/electricity/2020/index.php?t=lw, https://atb.nrel.gov/electricity/2020/index.php?t=su.

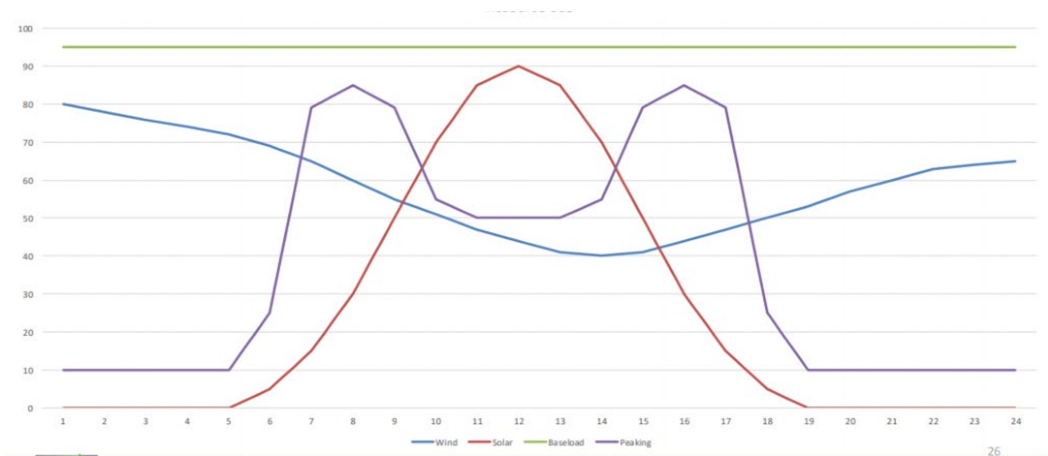
decrease. Should all coal generation units retire, there may be a marked decrease in diversity, as diversity indices are all vulnerable to threshold effects, as mentioned earlier.

Incorporating Generation Diversity into Planning

Xcel Energy provided a relevant case study. Upper Midwest customers comprise about half of its entire service territory, or 1.8 million electric customers in five states. Northern States Power, a subsidiary of Xcel Energy, covers the far western tip of Michigan's Upper Peninsula. At a high level, the main categories the company considers for diversity are resources, demand, and geography, though resource generation diversity was prioritized in this presentation. From a long-range planning perspective, storage adds another aspect-- the value of time diversity.

One way to approach resource diversity is to look at the different types of resource categories: "fuel saving variable renewables" (solar PV, solar thermal, wind, and run of river hydro), "firm low-carbon resources" (geothermal, nuclear, gas or coal with CCS, and biomass), "Fast burst" balancing resources (energy storage, flexible demand through rescheduling, and demand response through price responsive curtailment). Planning is conducted, in accord with how Marc Keyser (MISO) framed it, by considering the attributes of each resource. For instance, certain resources are dispatchable and used year-round. Others are intermittent, their output is not directly controlled by the utility and is dependent on variables such as weather. These characteristic differences between resources result in different generation profiles shown in Figure 7, where each variable resource has a vastly different profile.

Figure 7: Generation Profiles for Wind, Solar, Baseload, and Peaking Resources

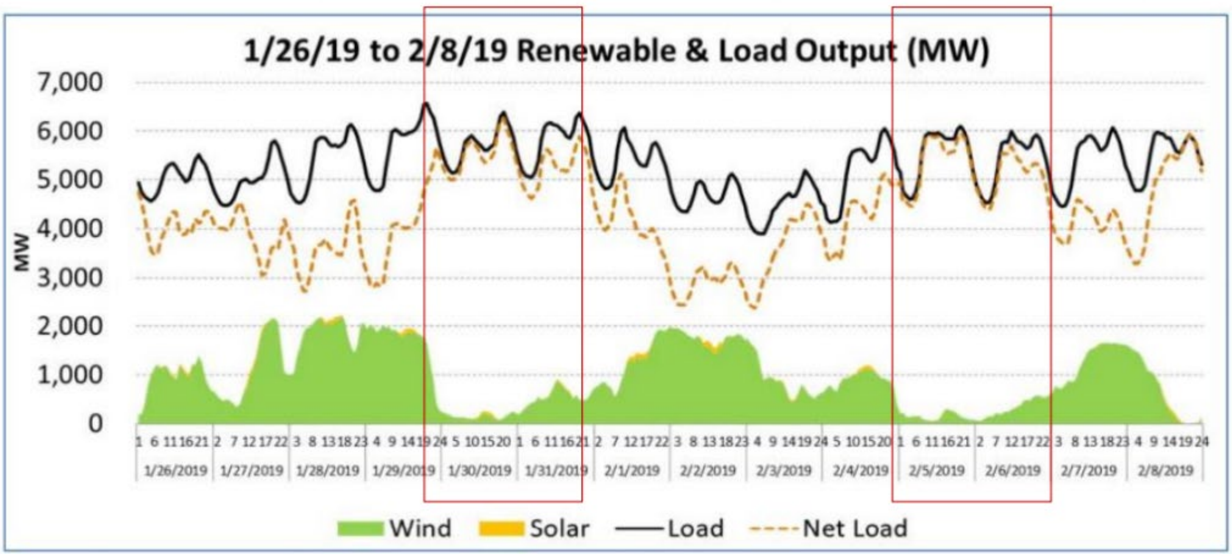


Taken from a slide of NSP's PowerPoint presentation, Feb 9, 2021.[81]

[81]https://www.michigan.gov/documents/mpsc/MPG_RDT_gif_Presentation_2.09.21_715688_7.pdf. Retrieved April 2, 2021, p. 26.

The value of generation diversity becomes apparent when atypical scenarios occur. For example, during January's Polar Vortex 2019 (PV19), wind and solar resource availability dropped off significantly. When temperatures dropped below 22 degrees Fahrenheit, wind turbines shut down because they were unable to operate effectively. Throughout PV19, net load almost followed the total load. Over-reliance on these weather-dependent resources could have meant a generation shortfall during PV19, which in turn can cause an LOLE. A similar example occurred a few days later, on Feb 5th, 2019, when the wind stopped blowing and skies were overcast, with net load following total load (shown in Figure 8). Gas, coal, and market purchases from RTOs (both MISO and PJM) filled in the gaps caused by the unfavorable weather.

Figure 8: Atypical Resource Profile Observed During Polar Vortex 2019 (PV19) and Several Days in February 2019



Taken from a slide of NSP's PowerPoint presentation, Feb 9, 2021.[82]

Summary of Requested Feedback

Generation diversity should be valued through risk assessment in an IRP. Modeling various generation portfolios, considering the costs of the diverse resources and the extent to which they can prevent certain risks, would provide a useful basis for customers and utilities to evaluate the costs, benefits, and value of resource diversity. IRP requirements should include a non-exhaustive list of analyses considered acceptable for risk assessment, including the aspect of generation diversity. A stochastic risk assessment will satisfy the diversity requirement and the stochastic risk assessment should be qualified as meeting this criterion. The evaluation of various generation

[82] https://www.michigan.gov/documents/mpsc/MPG_RDT_gif_Presentation_2.09.21_715688_7.pdf. Retrieved April 2, 2021, p. 27.

diversity scenarios should include different resource types and amounts to consider how such scenarios would support resource adequacy over the long-term.

There are two considerations for valuing generation diversity as part of the risk assessment, focusing on fuel cost variability and resource availability. Specific generation unit retirements should not be defined or mandated simply to pursue resource diversity; they should instead be considered through reasonable and transparent analyses which assess the costs and benefits of diversification and demonstrate economic impacts to avoid imprudent portfolio modifications. The inclusion of risk assessment should continue to be an approach that utilities can use as a sufficient methodology to address generation diversity in integrated resource planning. A level of flexibility to incorporate additional ways to assess generation diversity should be considered in recommended modifications to the IRP Filing Requirements. Stochastic risk assessment continues to be the preferred and recommended method to evaluate diversity more robustly while providing a quantitative value of risk. The assessment of generation diversity, however, should not be prescriptive; the value of such diversity, and to a degree the cost, is complex, dynamically affected, and qualitative in many ways. Ultimately, flexibility and deference should be afforded to each company to responsibly manage its business for the benefit of its customers.

Alignment of planning processes will help accurately value a diverse generation portfolio. The ability to evaluate the costs and benefits of various resource portfolios in multiple planning contexts would provide a fuller picture of the total costs and benefits that each resource type provides to customers. Increased alignment of planning processes through shared key inputs and assumptions could help identify the value of resource diversity, such as grid resiliency and resource adequacy. The value of a resource portfolio's diversity will vary depending on the planning context (i.e., resource, transmission, or distribution planning).

The inclusion of a specific calculation or value assigned to resource diversity is not recommended. It is most appropriate for each utility to assess and evaluate how to address resource diversity as an element of the risk assessment process, and then apply the available tools and evaluation methods to conduct additional analyses. Each utility should address generation diversity in its IRP. Generation diversity should be addressed through discussion of how the diversity of proposed course of action supports the needs of the system and its customers, and not a predetermined or defined calculation or methodology.

Staff Recommendations and Conclusion

Appropriately valuing generation diversity is a challenging task. Diversity itself holds no intrinsic value; it is the unique set of characteristics that each generation technology and fuel type bring to the grid that provide value. Diversity indices provide high-level looks at a resource portfolio's ability to mitigate risk and provide system reliability but fail to provide sufficient detail for meaningful insight or to guide decision-making. The desired outcome of generation diversity is a resource portfolio capable of meeting load under a wide range of circumstances. Running plans through a combination of deterministic and stochastic risk analyses will lead to the selection of more diverse portfolios.

As such, Staff recommends utilities conduct a stochastic risk assessment for their PCA, on all the optimized plans generated from the MIRPP base scenarios, and optimized plans generated on any utility-created scenarios. This does not mean the utility should perform a stochastic risk assessment on the sensitivities. Staff supports the use of deterministic risk assessments when deemed valuable by the utility, but the use of deterministic assessments should be supported as reasonable to assess the performance of a plan under a particular future.

For presenting the results of stochastic risk analysis Staff recommends that the NPV outputs be graphically presented in such a way that the probability distributions are clearly conveyed along with relative positions of the distributions so that plans can be directly compared on a single graph. Two examples are a box and whisker plot and an efficient frontier plot. Both display the risk for each plan and allow for side by side comparison. Further information on these two types of plots can be found in Appendix B and Appendix C. As for comparing each plan based on deterministic risk assessment, where each plan is run through each combination of scenario and sensitivity, Staff recommends using a matrix to display each optimized plan's NPV when run through each future.

While diversity indices may be of little use in the context of a single utility's IRP, they provide a helpful summation of overall resource characteristics and provide insight about grid effects. Staff recommends that it internally track state-wide generation diversity using the Modified Simpson, Stirling, and Shannon-Wiener indices based on both energy and capacity for the IRP planning horizon of 15-years, at 5-year intervals. Staff would update the current year indices annually, with projected years being updated after each round of IRP updates.

Finally, Staff recommends continued collaboration with stakeholders to further develop Staff's understanding of generation diversity and risk assessment.

Alignment of Distribution, IRP, and Transmission Planning

Background

Current Planning Integration Process

The MPSC and the relevant ISOs currently have several processes in place to assess resource, distribution, and transmission planning. Section 6t of PA 341[83] provides directional guidance for rate-regulated utilities to submit IRPs to the MPSC for review and approval on five-year schedules. All rate-regulated electric utilities submitted IRPs and received rulings from the Commission on those plans or an approved settlement agreement; the final being the approval of a settlement in

[83] MCL 460.6t of Public Act 341 of 2016.

I&M's IRP docket, Case No. U-20591, on September 10, 2020. The next IRP scheduled to be filed is Consumers Energy's in June of 2021.[84] The filings of the various utilities are staggered due to the large amount of scenario modeling, forecasting data, and stakeholder engagement required for each contested case. The IRPs have historically included coordination with transmission utilities and are required to include "[a]n analysis of potential new or upgraded electric transmission options for the electric utility," and "[p]lans for meeting current and future capacity needs… including any transmission or distribution infrastructure that would be required,"[85] by MCL 460.6t (5)(h) and (j), respectively. However, stakeholders have indicated that they would like to see more detailed transmission and distribution information included in future IRP filings as discussed in the forecasting and transmission planning sections of this report. One recent example is the I&M IRP Settlement in Case No. U-20591.[86]

The Commission also ordered the three largest Michigan utilities to file electricity distribution and maintenance plans every five years in its April 12, 2018 Order in Case No. U-20147. In its August 20, 2020 Order in that same case, the Commission stated it "sees value in aligning distribution plans and IRP filings and is interested in such an alignment to the best extent possible." CE, DTE, and I&M's next electric distribution plans are due by September 30, 2021.[87]

Transmission planning topics largely take place through the MISO MTEP Processes as well as the PJM RTEP Processes, as discussed in the Transmission section of this report. Commission Staff monitors the MISO MTEP and PJM RTEP process, and routinely engages throughout the process. As the utilities engage in IRP and distribution processes, transparency into these planning processes inherently increases for all stakeholders. Utilities are also required by statute to perform an analysis of new or potentially upgraded transmission options for the utility.[88] This ultimately provides a link between IRP and local transmission owner. However, this does not mean that the MISO-led transmission processes are linked to the IRP.

Although utilities engage in the MISO and PJM planning processes, the utility processes remain as bifurcated regional planning procedures. As the energy generation landscape continues to evolve, resource adequacy will become increasingly more important as older centralized-generation is retired and newer, variable decentralized-generation comes online. Predicting and planning for load will become increasingly more challenging. With the move toward electrification and increased penetration of DERs, the load will become more dynamic and unpredictable.

---

[84] In the matter of the application of Consumers Energy for the approval of its integrated resource plan pursuant to MCL 460.6t and for other relief, 6/7/19 Order, MPSC Case No. U-20165, Exhibit A, p. 3.
[85] MCL 460.6t (5), sections 5 (h) and (j), respectively.
[86] 9/10/2020 Order in MPSC Case No. U-20591, Settlement Agreement, p. 4.
[87] 8/20/20 Order in MPSC Case No. U-20147.
[88] MCL 460.6t Sec5(h) and (j)

NARUC-NASEO Project

The Commission participated in a partnership between the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Offices (NASEO). NARUC is a non-profit organization comprised of state regulatory commissions nationwide. It houses the Center for Partnerships and Innovation, which identifies emerging challenges and connects state commissions with strategies to support their decision making. NASEO is a non-profit organization that includes the 56 governor-designated energy officials from each state and territory; they work to improve effectiveness of state energy programs and policies, while acting as a repository of information on issues of concern to the states and their citizens. In February of 2019, the two organizations launched a new partnership: the NARUC-NASEO Task Force on Comprehensive Electricity Planning[89] whose purpose is to develop new pathways for aligned electricity planning. This task force involves 15 participating states, including Michigan, with a focus on the principles of innovation, action, and replication. Through multiple workshops, Michigan partnered with vertically integrated states to build a roadmap for state action plans. The final year of this effort occurs simultaneously with the MI Power Grid efforts overseen by the Commission and provides valuable synchronicity. The lessons learned from each of the processes provide valuable learnings to state regulatory commissions considering alignment of planning topics.[90]

The primary issues being addressed in the state cohorts closely align with the work taking place in this Advanced Planning Workgroup. For instance, the cohorts explored opportunities for stakeholder engagement, incorporated emerging planning methods (e.g., multi-scenario forecasting, non-wires alternatives), evaluated a range of solutions and procurement strategies, coordination of data assumptions between planning processes and modeling scenarios, and acknowledgement of DERs as a resource. Additional questions considered include rate design, resilience metrics, ensuring equity and affordability throughout the grid transition, tools and models needed for alignment, and transparency and security considerations with data access and data sharing. The partnership also published a comprehensive resource library, which includes 15 categories of publications and webinars of related topics explored.

Michigan's Largest Utilities' Perspectives

For the September 24, 2020 stakeholder session, Staff asked Consumers Energy, DTE Electric, and I&M to present the utilities' perspectives on alignment. Each utility is at a different point of integrating resource, distribution, and transmission processes. All trending towards more robust coordination and alignment between the various planning teams. Planning alignment is being spurred on by necessity; as supply sources continue to migrate into the distribution grid and plans

---

[89] www.naruc.org/taskforce/resources/

[90] Id.

involve both high voltage and low voltage distribution. Alignment of planning makes the coordination of these intertwined assets more manageable.

While the utilities are at different stages of alignment, each see similar challenges in achieving full integration of the planning processes. One of these challenges is translating high-level assumptions in transmission and resource planning to distribution planning. Differences in scope, objectives, and planning horizon also pose a challenge when attempting to align these processes. In addition to these high-level issues, there are practical challenges a utility must overcome. The traditional approach to planning does not facilitate the level of information sharing needed to integrate the plans. Data availability, information technology infrastructure, personnel skill sets, and insufficient modeling tools limit alignment due to the added complexities a fully integrated planning process requires. Integrating stakeholder input in distribution and transmission planning is also needed.

These are surmountable challenges, but they will take time to overcome. Organizational integration of all planning teams into a single linked organizational structure helps facilitate sharing of information and keeping the groups aligned with what the other groups are planning. The sharing of goals and objectives, metrics, budgets, and forecasts allow leadership to evaluate progress and ensure common goals and financial direction. This is a continual process that requires active engagement of leadership with the different teams. This integration process allows the teams to share emerging trends, translation strategy, and signpost goals. Efforts should also be made to bring awareness to what other groups are doing and to include those outside the planning teams. Several presentations also addressed internal efforts required in utility structure and organization that allow the various internal planning teams for distribution, transmission, and resource planning to coordinate long-term decisions and modeling would allow for a more fully integrated planning process. Staff encourages this coordination and increased awareness brought to this issue.

Discussion

Importance of Aligning Processes

Integrated resource planning, distribution planning, and transmission planning are three essential components to ensuring a safe, reliable, and accessible energy at reasonable rates. Traditionally, these processes are considered separately in Michigan by utilities, regulators, and stakeholders. Utilities were not required to file an integrated resource plan until PA 341 was signed into law in 2016. PA 341 requires utilities to submit Integrated Resource Plans, but the IRP, distribution plan, and transmission plan are currently designed, modeled, and run as separate planning processes, thus creating a gap as resources become more intermittent and distributed. Fully aligning these planning processes would facilitate holistic grid solutions and efficient integration of new technology and distributed generation to ensure that ratepayers are able to access all the benefits of a fully integrated electric system. In the various stakeholder meetings held on alignment topics, many ways to facilitate integrated planning were suggested by utilities, independent power producers, governmental bodies, and national laboratories.

The Electric Power Research Institute (EPRI) and Regulatory Assistance Project (RAP) provided some examples of grid improvements to the IRP, distribution planning, and transmission planning process at the October 21, 2020 stakeholder session. Energy waste reduction and renewable energy targets set at the jurisdictional level impact system demand and resource investment decisions on both the transmission and distribution system. The journey to electrification also requires intensive integration between resource, transmission, and distribution planning, including the impact of EV charging on load and the integration of energy storage. Coordination between resources and loads will ensure the electric grid will be able to meet customers' needs on all parts of the grid at all hours of the day for every day of the year. Without detailed coordination between the various planning processes, the transition to cleaner and more distributed resources becomes difficult to adequately plan for. At the very least, each planning process needs coordinated modeling inputs and integrated methods to ensure each planning process begins with the same data, calculated with the same methods to the extent practicable. Scenario coordination between the processes allows evaluation of renewables, electrification, and other new load types and shapes across the whole grid using consistent data and assumptions of future conditions. Evaluation of the same scenarios across transmission, distribution, and resource planning will more clearly demonstrate the affects between them. Additionally, processes with the same initial data are more able to be compared between one another. Currently there are a plethora of new ideas for coordinating new loads and novel solutions for transmission and distribution systems, but both require coordination with the other to ensure resource availability, value streams, and reasonable overall cost. For example, coordination between distribution grid storage and transmission needs can give a quicker reaction time and more efficient discharge/recharge of the storage unit where it is most needed to support electric system function.

The addition of DERs to the grid adds a layer of complexity to distribution and transmission system planning that further necessitates the alignment of planning processes. The shift away from static, one-directional flow to a dynamic model where power may also flow from the distribution system to the transmission system presents a significant challenge to both the electric grid and planning models. Large numbers of DERs and NWAs on the distribution system impact the transmission system, as described in prior sections. In some instances, these impacts are a benefit to the transmission system by providing ride-through capability and frequency and voltage impacts.

Alignment of planning processes allows for coordinated data assumptions, modeling scenarios, and DER and NWA assumptions between separate entities and within organizations to promote a more adaptable, reliable, and resilient electric grid for Michigan ratepayers.

Integration of Distribution Generation and Non-Wires Alternatives

Some stakeholders focused on the alignment of distribution planning with the IRP and called for more transparency in the distribution planning process. Increased transparency allows more insight into how NWAs are considered in distribution planning and allows for co-benefits to be considered in an IRP. NWAs are proposed as solutions to alleviate many grid congestions, overloads, and contingencies. NWAs can be considered as incremental solutions for uncertain load growth that defers or obviates the need for expensive distribution infrastructure upgrades by installing a targeted solution such as EWR, DR, distributed generation, or storage.[91] Thus, NWAs have a locational value to the distribution system while also providing resource adequacy benefits. To fully assess the benefits of NWA projects, both the locational value and the resource value must be considered.

To better identify areas where NWAs should be considered, a circuit level needs assessment that identifies circuits where there are known constraints and where the system age and condition are not a concern as part of the distribution planning process would prove helpful. Then, as the IRP is conducted, distributed resources selected by the model or deemed to provide needed system support can be planned in a location that provides the most system benefit and locational value. Stakeholders identified a need for information flow between the IRP and DP processes and that information flow is an iterative cycle, not a one-time event. Creating transparency into the needs of the distribution system is a first step in starting the integrative information flow process between DPs and IRPs.

Stakeholders also identified a need for sufficient lead-time to consider NWAs as solutions for distribution system and transmission system needs. NWAs can provide benefits to the transmission system and distribution system and, they need to be adequately studied in both planning processes to determine what those projected benefits are. Therefore, the planning processes and information flow between the planning processes must be iterative. The information for distribution planning and transmission planning can identify resources that could provide targeted benefits. This is necessary information for the resource planning process when utilities are considering investment in a variety of resources. Stakeholders pointed out that the current transmission, distribution, and resource planning cases are linear, there will be some difficulty iterating. Staff finds that although the cases do follow a linear timeline once filed, distribution, resource, and transmission planning are continually happening within the regulated utility, TO, and RTO organizations. Stakeholders generally agreed that increased communication extending beyond the planning process cycle is necessary to ensure information from each process flows into and out of the others. Staff's perspective is that typical planning processes can continue, provided that the flow of information from any single planning process to another is continuous, and therefore iterative, to reflect the most recent developments in all planning processes.

Utilities in Michigan are beginning this process by considering the potential use of NWAs in distribution planning and aligning with IRP by considering DERs in resource selections that could be deployed in such a way to achieve locational benefits and thus become NWAs. Staff

[91] Homer (PNNL) MI Power Grid Advanced Planning Presentation Oct 21, 2020.

understands that there are challenges and limitations of software and the divested nature of Michigan's system that limit the ability for a full analysis across the entire electric system. The addition of a distribution needs assessment in distribution planning that could be occasionally updated directly referenced in an IRP to support proposed IRP investments would provide both transparency and generally support iterative planning.

Organizational Alignment

During the October 21, 2020, November 6, 2020, and November 18, 2020 stakeholder meetings, PNNL's Juliet Homer, EPRI's Adam Diamant, NREL's Brady Cowiestoll, Dominion's Bob Thomas, and Duke Energy's Michael Rib all discussed the disconnect between the distinct processes across generation, transmission, and distribution planning and the need to align these processes using a "bottom up" approach, with consideration given to generation at the distribution level. The alignment of transmission and distribution planning is becoming increasingly important, along with the need to improve communication between different planning functions to create holistic planning, which can be advanced by aligning planning functions within an organization. The Integrated Energy Network Planning (IEN-P) report was discussed along with the 10 critical resource challenges - one of which includes integrating generation, transmission, and distribution planning.[92] Dominion's and Duke Energy's presentations went a step further, emphasizing the importance of organizational and personnel changes to promote a shared ownership of one consolidated plan across all planning processes. This ensures that there are common goals and objectives across all planning processes. Although Staff understands that this is a major undertaking for regulated utilities, Staff recommends Michigan utilities consider aligning organizational structures internally to facilitate internal communication and alignment of utility goals across all utility planning processes.

Data Analytics and Accessibility

During the October 21, 2020 stakeholder meeting, PNNL's Juliet Homer explained the challenge of understanding DER profiles and forecasting with the utility's lack of visibility of data on customer-owned systems. Lessons learned focused on the need for new analytical techniques and tools, along with integrated planning between the various tools, to effectively respond to DERs and renewables connected to the grid. To date, utilities have used more of a traditional focus to ensure peak loads are met by reviewing distribution feeders or annual growth to determine the need for expansion, which is left to the planner's discretion. With the traditional planning concept in mind, speaker presentations commonly referred to the need for more granular information using data analytics tools to understand the effects of DERs and renewables on the system, allowing access to the granular information, and the need to align the information in a way that

[92] Developing a Framework for Integrated Energy Network Planning (IEN-P), Executive Summary: 10 Key Challenges for Future Electric System Resource Planning (epri.com).

promotes consistency and benefits across the entire spectrum of planning processes. LoadSEER, CYME, NREL's dsgrid, dGen, DISCO, and WattPlan Grid were among the multiple load and DER forecast tools discussed through presentations. Presenters also discussed state-specific data requirements, some of which require customer-usage data to be accessible through applications such as Green Button, while others require system-level data sharing through hosting capacity maps to improve data accessibility and overall transparency at the distribution level.

The idea of holistic planning does, however, come with challenges due to traditionally separate tools and modeling across the various levels of planning, which were alluded to. Duke Energy presented the Integrated System & Operations Planning (ISOP) framework, which was created to drive optimization of the planning processes through collaboration across all planning processes, while NREL presented its Resource Planning Model (RPM) as a regional and utility scale resource planning tool which interacts with distribution models. Both acknowledge that there is no current tool that allows for fully integrated planning, but rather utilities and stakeholders continue to seek out ways of using existing tools in different ways to align planning more fully.

The lack of fully developed tools in turn places more emphasis on the need for consistency and timing between planning processes. It is critical that consistent objectives and assumptions are applied to distribution plans, transmission plans, and IRPs to ensure that the results from all planning processes are aligned. Likewise, to the extent practical, timing should be considered. Although fully aligned timing is not likely practical, Staff suggests that all planning processes should in essence speak to one another. Stakeholders, Staff, and utilities should be able to trace how assumptions, inputs, and plan outputs flow into and out of all planning processes. To that end, Staff recommends consistency, coordination, and transparency in utility planning processes.

Communication and Transparency

Today's planning processes are not designed to develop holistic solutions. As discussed in the Transmission section of this report, this is a particularly difficult hurdle to overcome given the bifurcated system ownership structure. To continue to make steps toward aligning planning processes and developing the solutions that provide the most benefit to ratepayers, Staff recommends utilities engage regional transmission owners by continued communication throughout all phases of resource and distribution planning. Continued communication between transmission owners and utilities is necessary because planning between distribution, transmission, and IRPs should be iterative. No one planning process feeds solely into another, rather, all the planning processes feed into all others, and establishing a consistent line of communication is key to information sharing.

Stakeholders highlighted a need for increased transparency and consistency. As discussed by experts from Duke, Dominion, EPRI, PNNL, and NREL, consistent assumptions that are transparently available to stakeholders become more important as planning processes are aligned.

Stakeholders also highlighted that the timelines of planning processes continue to differ. Each planning process works on a different planning cycle. Therefore, it is important that stakeholder engagement happen throughout all planning processes. Utilities continue to facilitate stakeholder engagement in their distribution plan and IRP processes through technical meetings, stakeholder meetings, and public outreach. Staff supports this ongoing effort. As suggested in the Transmission section, stakeholders are also encouraged to participate in the regionally established stakeholder processes at both MISO and PJM to ensure that those regional processes fully consider all transmission and non-transmission solutions. Ongoing communication and engagement with stakeholders further facilitate transparency across all planning efforts, ensuring that stakeholders have a full understanding of utility decisions in planning processes.

The Iterative Nature of Electric Grid Planning

As discussed earlier, Staff views DP, TP, and IRP alignment as able to be achieved through an iterative process. All plans feed into all other plans; there is no start and end to the process. This is because inputs into one planning process often come from another and, likewise, outputs from one process feed into another. The iterative nature is critically important when planning the future electric system because information needs to flow bi-directionally. For example, a distribution system can be reviewed from multiple perspectives. In one case, it can be reviewed to determine where distribution-scale resources can be connected, and the result is a hosting capacity analysis. In another case, it can be reviewed to determine where distribution-level resources with certain characteristics may help alleviate a constraint, and the result is a distribution needs assessment. One may inform the IRP process as to how many of certain resources the distribution system could benefit from, while the other helps to define a limit. Both the hosting capacity and needs assessment will change over time as new resources are added, thereby demonstrating the iterative nature between DP and IRP. A similar example can be made between transmission plans and IRP processes and distribution planning and transmission planning processes.

Bi-directional flow of information and iterative planning can identify where the most beneficial locations are for resources and where locational loads are changing, resulting in system benefit from targeted programs. Specifically, identifying high circuit loading, opportunities for economic non-wires alternative investment, locations of highly distributed energy resource penetration, and the locational impacts of electrification, such as electric vehicle penetration, continue to transform the grid; therefore, iterative planning allows for informed decisions that will result in the most benefit to ratepayers throughout this transformation.

Staff Recommendations and Conclusion

Participants provided information throughout the MI Power Grid Advanced Planning stakeholder process. The information provided by subject matter experts, coupled with the discussion and feedback from several engaged stakeholders and utilities throughout the process, has led Staff to identify several recommendations for the Commission to consider as it provides guidance for future updates to the MIRPP, which will commence at the start of Advanced Planning Phase III. As the electric system continues to undergo a transformation while enabling clean, renewable energy resources, aligning planning processes is critical to providing safe, reliable, and accessible electricity at affordable rates. A number of these recommendations reiterate similar themes to those identified in other sections of this report, reinforcing their importance.

Increased Consistency and Coordinated Timing

Staff recommends increased consistency throughout the planning processes and coordination of timing between processes. These two items go hand-in-hand. Consistent assumptions throughout planning processes will advance the efforts to align those processes, while coordinated timing will ensure that the information provided in one plan can directly link to another. Consistency extends beyond consistent assumptions in modeling and providing for consistency between forecasts; it includes maintaining consistent goals and vision across parts of the utility organization. Therefore, Staff also recommends that utilities consider aligning their organizational structure to better facilitate aligned planning. Staff's recommendation for coordinated timing should not be misconstrued to mean that planning cycles for distribution plans, transmission plans, and IRPs should all start and end at the same time; rather, the timing of the planning efforts should be coordinated to ensure the information flow from one process to another is consistent and accurate, so that a link between processes can be made between various inputs, outputs, and resulting decisions, allowing all parties to clearly identify how one plan feeds into another and vice versa.

Increased Communication and Transparency

Staff recommends increased communication and transparency. Bi-directional communication and information flow in all aspects of planning, both within utility organizations and with stakeholders, is crucial. In addition, the communication should not stop once a planning cycle is complete; it should be continuous, as an open flow of information facilitates increased transparency in all aspects of the planning processes and helps to inform all parties involved. Given Michigan's bifurcated structure with a divested transmission system, communication is the only way to bridge the gap between disconnected planning processes and create alignment. Additionally, utilities continue to increase stakeholder engagement and public outreach. Staff supports these efforts. Utility-Stakeholder technical meetings between, before, and during cases ensure that stakeholders are aware of the latest opportunities and challenges. The importance of public outreach cannot be emphasized enough either; as the grid becomes more dependent on its users to provide load flexibility, a bi-directional relationship between customer and utility becomes paramount. All these communication efforts require substantial time and effort; utility planning needs to account for that and allot the necessary time and resources.

Iterative Planning

Staff recognizes DPs, TPs, and IRPs are iterative planning processes. Needed investments in one planning process will have impacts on all other aspects of the electric grid planning. The recommendation for consistency, transparency, communication, coordinated timing, and continuous stakeholder engagement support the iterative nature of electric system planning. Staff recommends that utilities engage in planning as an iterative process, providing a clear link about how each planning process impacts another, and identify where there are opportunities for distribution and transmission to support resource development, investment in resources to support the distribution and transmission grid, and how distribution and transmission planning can be used to support one another. In essence, Staff is recommending that there be a clear conversation happening at regular intervals, such that stakeholders and Staff can follow from one planning case or activity to another, that establishes linkages between all planning processes. Identification of distribution system, transmission system, and resource needs and opportunities will allow for locational benefits, increased reliability and resilience, and technology advancements to be fully realized for all customers.

Emissions and Environmental Considerations

Status Update on Staff's Emission Report

On September 23, 2020, Governor Whitmer issued Executive Directive (ED) 2020-10, which announced the "MI Healthy Climate Plan," in conjunction with Executive Order (EO) 2020-182. Through this action, "Michigan committed to pursue at least a 26-28% reduction below 2005 levels in Greenhouse Gas Emissions (GHG) by 2025 and to accelerate new and existing policies to reduce carbon pollution and promote clean energy development at the state and federal level."[93] Further, she asserted that "Michigan will aim to achieve economy-wide carbon neutrality no later than 2050, and to maintain net negative greenhouse gas emissions thereafter."[94] In order to develop a comprehensive and coordinated plan to meet the goals of ED 2020-10, Governor Whitmer provided a list of directives to State departments and agencies, which direct the Michigan Department of Environment, Great Lakes, and Energy (EGLE) to expand its advisory opinion filed in accordance with MCL 460.6t and IRPs filed under MCL 460.6s and evaluate whether utility IRPs are consistent with the emission reduction goals set forth in ED 2020-10.[95]

In light of this ED, the Commission issued additional guidance in Case No. U-20633 establishing this workgroup, stating "that the process of updating the utility IRP parameters and filing requirements should take into account the goals set by Michigan's utilities and how those goals align with greenhouse gas emission targets set by Governor Whitmer."[96] In that same Order, the Commission noted that Consumers Energy, Upper Michigan Resources Corporation (UMERC), and I&M will begin filing IRPs in 2021, and therefore it is imperative for Staff to develop timely recommendations for these utilities to consider the emission reduction targets set by Governor Whitmer.

---

[93] Executive Directive 2020-10, https://www.michigan.gov/whitmer/0,9309,7-387-90499_90704-540278--,00.html, retrieved March 16, 2021.
[94] Id., p. 2.
[95] Id.
[96] MPSC Order 10/29/20 p. 6.

In response to ED 2020-10 and the Commission's subsequent Order in U-20633, Staff filed a report titled "Emissions Reporting Requirements for Utility IRPs" on December 15, 2020.[97] Based on feedback from stakeholders, Staff's proposal presented two compliance options for utilities filing IRPs prior to the next updates to the MIRPP and IRP filing requirements, including separate compliance options for multi-state utilities. Option One instructs utilities to perform one additional IRP modeling run that illustrates a path toward carbon neutrality in an electrification future and meets the interim goal of a 28% reduction in carbon emissions from 2005 levels by 2025, while continuing along a trajectory toward net zero carbon emissions by 2050. Option Two presents a more aggressive carbon reduction goal, directing the utilities run an additional modeling run which illustrates a path toward carbon neutrality in an electrification future by achieving an electric sector goal of 32% reduction in carbon emissions from 2005 levels by 2025.

Staff recommended that multi-state utilities filing prior to the next update to the MIRPP, and IRP Filing Requirements should be directed to perform an additional modeling run that shows how its MI service territory will meet the carbon emissions reduction goals set forth in ED 2020-10. Staff also presented an alternative, proposing the Commission could allow multi-state utilities more flexibility to demonstrate compliance with the carbon emission goals; this would require supporting testimony and exhibits providing information from the utilities' existing scenarios that illustrate an electrification and carbon neutral future in its Michigan service territory. The supporting evidence must show the overall impact to load, utility resources, and emissions, while demonstrating a path towards the ED 2020-10 carbon emissions reduction goal.

Following the report, stakeholders were given an opportunity to file comments on Staff's report by January 12, 2021. The issues highlighted by stakeholders and utilities in their respective comments varied. Discussion and comments centered around two main themes. The first theme was expected load growth in a carbon neutral future. Some stakeholders project a significant increase in load due to electrification, while many others agreed that these load changes were uncertain at this time. Uncertainty around how behind-the-meter-generation will impact and serve load in a future with greater electrification was also discussed. All parties agreed that the load growth is not likely to be linear. The second theme was the appropriate level of carbon reduction that should be expected from the electric sector as compared to other sectors to achieve the economy-wide goals established in ED 2020-10. Stakeholders offered varying viewpoints, ranging from all emission reductions necessary by 2025 should be achieved by the electric sector, assuming no continuation of existing decarbonization trends in other sectors, to all other sectors being responsible to achieve the appropriate reduction in their respective sector.[98]

---

[97] Emissions Reporting Requirements for Utility IRPs.
Appendices_MPG_Integration_of_GDT_Planning_Emissions_Update_Report_710803_7.pdf (michigan.gov).
[98] Stakeholder comments on Staff's report are filed in MPSC docket U-20633.

On February 18, 2021, the Commission issued an Order in U-20633 that directs the utilities filing near-term IRPs, or those filed prior to the MIRPP and IRP Filing Requirement updates, to conduct two additional model runs.[99] The runs stem from Staff's two options but incorporate feedback on expected changes to load growth and accounting for carbon in market purchases.

After the Commission Order, stakeholders asked for clarification regarding the appropriate values to use for the annual average carbon associated with MISO and PJM market sales. Staff convened a meeting with the three utilities filing in 2021 to further discuss the matter. Several methodologies were discussed, which included obtaining historic carbon amounts from the RTO, using RTO projected amounts from one of the several RTO models, modeling the market during optimization runs to obtain a modeled amount of carbon for the planning period, and the use of a utility fleet average as a proxy for a market value, to name a few. No consensus was reached; however, utilities are expected to support their market carbon assumptions in their individual IRP filing.

It was also noted by MISO that counting the carbon associated with both purchases and sales may result in double counting if the carbon numbers in utility IRPs are compiled to provide a statewide carbon reduction estimation. Many transactions that a utility engages in are with other utilities within Michigan, and therefore one utility would be counting a purchase while the other is counting a sale. The result is counting the same carbon emission twice. Likewise, in the future, if other states in MISO have similar carbon goals, and if those purchases and sales are counted in both Michigan and another state, double counting would also occur. However, Staff determined that because IRPs are utility-specific, counting carbon for both market purchases and sales does provide a utility-specific view on its resource plan and the impact to carbon emissions. Staff recommends that further consideration be given to counting market carbon during the Advanced Planning workgroup during Phase 3 and any direction from EGLE also be integrated into the IRP process, when the draft MIRPP and IRP Filing Requirements are discussed.

Status Update on Environmental Justice and Public Health Coordination

Statutory language from MCL 460.6t(7) describes the identification and consideration of "all applicable state and federal environmental regulations, rules, and laws." Specifically, the law states the following:

> The commission shall request an advisory opinion from the department of environmental quality regarding whether any potential decrease in emissions of sulfur dioxide, oxides of nitrogen, mercury, and particulate matter would reasonably be expected to result if the integrated resource plan proposed by the electric utility … was approved and whether the

[99] 2/18/21 MPSC Order Case No. U-20633.

integrated resource plan can reasonably be expected to achieve compliance with the [identified] regulations, laws, or rules…" (MCL 460.6t(7))

As part of the MI Integrated Resource Plan Parameters (MIRPP), developed in 2017 with significant stakeholder feedback, the Commission identified significant environmental regulations and laws that affect electric utilities.[100] Included among these relevant environmental regulations are:

- The Clean Air Act
- The National Ambient Air Quality Standards
- Sulfur Dioxide Nonattainment Areas
- Cross-State Air Pollution Rule
- Mercury and Air Toxic Standards
- Clean Air Act
- Greenhouse Gas Reporting Program
- Boiler Maximum Achievable Control Technology
- Regional Haze
- Resource Conservation Recovery Act
- Clean Water Act
- Steam Electric Effluent Guidelines
- Michigan Mercury Rule
- Michigan Environmental Protection Act[101]
- Solid Waste Management Program (Part 115)
- Ozone Nonattainment Areas

EGLE has provided an Advisory Opinion (AO), filed as a report to the docket in lieu of testimony, for each IRP filed throughout 2018 and 2019. These reviews take place across four divisions within EGLE: Air Quality Division, Materials Management Division, Water Resources Division, and Remediation & Environmental Redevelopment. Technical staff from each of the respective divisions review the IRP under the purview of the applicable environmental rules and regulations

---

[100] Michigan IRP Planning Parameters pursuant to PA 341, Section 6t. [Michigan Integrated Resource Planning Parameters](#).

[101] CL 324.1701 – 324.1706. MCL 324.170 governs the application of MEPA in administrative hearings. The statute states: (1) If administrative, licensing, or other proceedings and judicial review of such proceedings are available by law, the agency or the court may permit the attorney general or any other person to intervene as a party on the filing of a pleading asserting that the proceeding or action for judicial review involves conduct that has, or is likely to have, the effect of polluting, impairing, or destroying the air, water, or other natural resources or the public trust in these resources.
(2) In administrative, licensing, or other proceedings, and in any judicial review of such a proceeding, the alleged pollution, impairment, or destruction of the air, water, or other natural resources, or the public trust in these resources, shall be determined, and conduct shall not be authorized or approved that has or is likely to have such an effect if there is a feasible and prudent alternative consistent with the reasonable requirements of the public health, safety, and welfare.

they oversee. Then, a summary from each section is compiled into one comprehensive narrative describing the utility's compliance, or lack thereof, to each of the relevant divisions, though no overarching agency determination is denoted. EGLE has access to all materials within the utility's filing and coordinates with MPSC Staff and the filing utility to obtain further information through the discovery process.

Although the MPSC as a rate regulator is granted some authority over environmental determinations under MCL 406.6t, EGLE has ultimate authority as the primary environmental regulator. This is also consistent with the language about the advisory opinion in MCL 460.6t(7) in determining "whether the integrated resource plan can reasonably be expected to achieve compliance with the regulations, laws, or rules identified in subsection (1)." As directed by statute, the Commission is limited to the evidence within the record in its review and determination within a utility IRP formal proceeding. Thus, it is imperative that EGLE and other parties interested in environmental application fully consider the applicable environmental laws, rules, and regulations be included in the record, so the Commission can consider it when making its determination about the case.

The Michigan Environmental Protection Act is one regulation that has been highlighted in recent IRP cases and in both ED 2020-10 and EO 2020-182.[102] The Commission has noted that issues related to MEPA and the potential impact of utility plans on public health have been raised in several past cases before the Commission. (See Cases Nos. U-18418, U-18419, U-18461, U-20471, and U-20350). In its Final Order in DTE Electric's IRP, the Commission expressed its desire to expand MEPA and EJ review in IRP proceedings. It stated,

> "In future proceedings, the Commission expects to coordinate with EGLE on the inclusion of public health and environmental justice considerations as part of the environmental information EGLE shares with the Commission under MCL 460.6t. Public health impacts are inherent in EGLE's responsibilities as an environmental regulator, as many laws, rules, and permitting requirements are tied back to health and environmental indicators."

Later in 2020, when the Commission introduced the August 20 Order in Case No. U-20633 launching the directives included for the MI Power Grid Advanced Planning workgroup, it noted the specific historic case application of the MEPA to utility planning. The Commission's Order also noted that the Michigan Interagency Environmental Justice Public Response Team,[47] created by Governor Whitmer, acts in an advisory capacity on environmental justice issues, and the Commission participates in the response team activities. Reiterating the language from the DTE Electric Final Order pertaining to MEPA, the Commission directed Staff to coordinate with EGLE on the inclusion of appropriate public health and environmental justice considerations in future

[102] MCL 324.170.

IRP cases, and to include a status update and any related recommendations in the May 27, 2021 report.[103]

Additionally, when Governor Whitmer announced the climate goals and climate council in ED 2020-10 and EO 2020-182 respectively, she also prescribed specific guidance for the Advisory Opinion process in future IRPs. The Directive stated:

> "The Department must expand its environmental advisory opinion filed by the Department in the Michigan Public Service Commission's (Commission") Integrated Resource Plan (IRP) process under MCL 460.6t and also file environmental advisory opinions in IRPs filed under MCL 460.6s. The Department must evaluate the potential impacts of proposed energy generation resources and alternatives to those resources, and also evaluate whether the IRPs filed by the utilities are consistent with the emission reduction goals in this Directive. For advisory opinions relating to IRPs under both MCL 460.6s and MCL 460.6t, the Department must include considerations of environmental justice and health impacts under the Michigan Environmental Protection Act. The Commission's analysis of that evidence must be conducted in accordance with the standards of the IRP statute and the filing requirements and planning parameters established thereto.[104]

MPSC Staff has been coordinating with the EJ Public Advocate and EGLE technical staff on an ongoing basis on these issues over the past year.[105] These meetings include EGLE technical staff from the Air Quality Division, Water Resources Division, Materials Management Division, and Remediation & Environmental Redevelopment; staff from its Executive Office and the EJ Public Advocate; MPSC technical Staff who work on IRPs; the Commission Office; and the MPSC Chief Operating Officer. The meetings have discussed the additional potential environmental, public health, and environmental justice data needs to support a revamped and informed advisory opinion. To that end, the agencies mutually developed a proposed list of additional environmental considerations that utilities filing in 2021 are requested to supply, which could help support the advisory opinion and comply with the direction from Governor Whitmer and Commission orders. Following multiple discussions with both State agencies, Consumers Energy agreed to most of the items requested, given the limited feasibility and impending timeline of their upcoming filing. Technical Staff from the MPSC and EGLE are continuing to coordinate on appropriate data asks for the two other utilities that have filings in 2021 to comply with the guidance on including EJ and public health.

---

[103] Commission Order in Case No. U-20633, August 20, 2020.

[104] ED 2020-10, pp. 2-3.

[105] The Office of Environmental Justice established a working definition: "EJ is the equitable treatment and meaningful involvement of all people regardless of race, color, national origin, ability, or outcome and is critical to the development as well as the places people live, work, play, worship, and learn."

Environmental justice topics were also discussed at two of the MI Power Grid stakeholder meetings. On November 18, a Staff member presented the MPSC's work on Environmental Justice in coordination with actions of the Interagency EJ Task Force.[106] The EJ Public Advocate also presented at the March 2nd, 2021 stakeholder meeting and discussed engagement opportunities in 2021, including regional roundtables and the announcement of a statewide EJ Summit. Additionally, Commission Staff presented IRP information to the Michigan Advisory Council on Environmental Justice[107] on February 18th and considered related comments from the council.

The Office of the Environmental Justice Public Advocate, the Michigan Advisory Council on Environmental Justice, the Michigan Interagency Environmental Justice Response Team, and the Michigan Department of Environment, Great Lakes, and Energy also held a multi-day Michigan Environmental Justice Conference. The Conference was held May 18-20, 2021. The virtual conference engaged stakeholders on a wide range of environmental justice topics allowing for across-the-board participation, dialog and continued quest for transformational change.

Staff expects conversations on including an EJ and public health analysis will be revisited during Phase 3 of the MI Power Grid effort, specifically when addressing revisions to the filing requirements and MIRPPs. In summary, the status of the coordination between the MPSC and EGLE on EJ and public health resulted in the following:

- Ongoing meetings and coordination between the MPSC and EGLE technical staff, deepening understanding of application and review of environmental and emissions data.
- Multiple presentations to MPG stakeholders as well as those members of the MAC EJ and Interagency Response Team, collecting feedback on process improvements.
- Coordination and development of a list of additional environmental data requests for utilities to include in upcoming IRPs.
- An improved coordination strategy of State agencies' response to the Governor's EO and ED addressing environmental justice considerations.

Conclusion

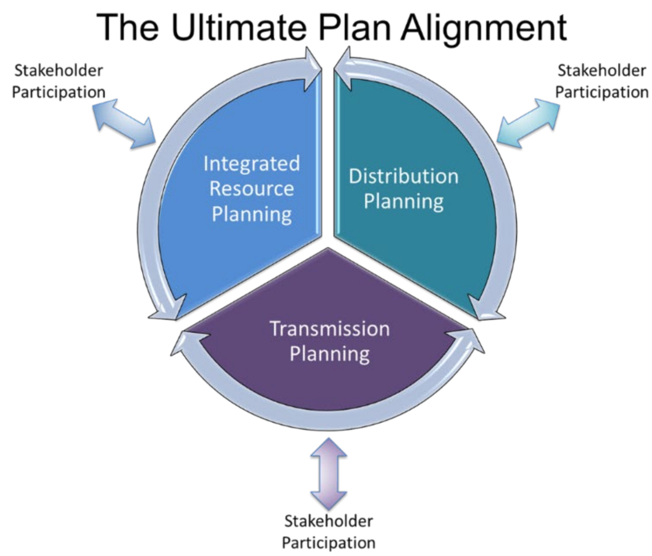
The MI Power Grid Phase II Advanced Planning Processes stakeholder effort focused on the Integration of Resource/Distribution/Transmission planning because regulated utilities,

[106] Executive Directive 2019-06 established the Office of Environmental Justice Public Advocate and named Regina Strong to the post. Shortly following, the Interagency Environmental Justice Response Team ("Response Team") was established, which consists of Department Directors of multiple State agencies. It was charged with assisting EGLE in development of a statewide EJ plan, as well as making recommendations to address discriminatory public health or environmental effects of state laws, regulations, policies, and examine disproportionate impacts.

[107] The Michigan Advisory Council on Environmental Justice consists of 21 members of the public who have specialized expertise in environmental justice issues affecting the state. These individuals represent community groups, academic, businesses, labor, tribal, municipalities, and other public sector interests.

transmission owners, and stakeholders currently engage in separate planning processes to make decisions about investments in the electric resource mix, transmission system, and distribution system. The decisions made in each one of these discrete planning processes impact all other planning processes and the ratepayer. By better integrating and aligning planning across the whole electric system, holistic planning can help to maximize benefits to ratepayers. Figure 9 illustrates Staff's vision of fully integrated planning.

Figure 9: Fully Integrated Planning



This report provides several recommendations addressing forecasting, transmission planning, valuing generation diversity, overall planning alignment, environmental justice, and distribution planning. These recommendations aim to better align resource planning with distribution planning, transmission planning, and the Governor's focused efforts on environmental justice. Staff's recommendations are intended to serve as a framework to guide future updates to the Michigan Integrated Resource Planning Parameters, as required by MCL 460.6t and the Filing Requirements. Staff will use this report and the Commission's response to develop a redline draft update to the existing MIRPP and Filing Requirements documents that it intends to use to facilitate discussion among stakeholders and regulated utilities at the start of the MI Power Grid Phase III Advanced Planning Stakeholder Process that is expected to begin later this year.

Staff appreciates all the time, effort, and thoughtful engagement from everyone involved in this process. The insights gained through this process provide a strong foundation for future discussions and the important decisions made in resource, distribution, and transmission planning efforts. Staff looks forward to continuing these discussions with a focus on updating the MIRPP and Filing Requirements in the near future.