INTEGRATED RESOURCE PLANNING REPORT

to the:

Indiana Utility Regulatory Commission

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Executive Summary

Overview

This 2021 Integrated Resource Plan (IRP, Plan, or Report) is submitted by Indiana Michigan Power Company (I&M or Company) based upon the best information available at the time of preparation. The purpose of the IRP is to develop a set of supply- and demand-side resources that guides how I&M generates and supplies electricity in a way that balances affordability, sustainability, and reliability.

This Plan is not a firm commitment to specific resource additions or other courses of action over the period of the plan, as the future is uncertain. The Plan provides the basis for a short-term course of action and strives to maintain optionality in meeting I&M's resource obligations in order for the Company to take advantage of market opportunities and technological advancements. Accordingly, this IRP includes a near-term plan, 2022 – 2028, and a long-term-indicative plan, 2029 – 2041, based on a number of assumptions that are subject to change as new information becomes available or as circumstances warrant. The near-term plan has the least uncertainty and the Company's Short-Term Action Plan described herein includes action items for the 2022 to 2024 period.

I&M[1] is on the brink of a major generation transformation as Rockport Unit 1 and Unit 2 will retire by the end of 2028. These coal-fired resources represent nearly one-half of the Company's generation fleet and the retirement of these units provides a significant opportunity for I&M to transition to more renewable resources, further diversify I&M's generation portfolio, and reduce its carbon emissions. At the core of this transformation must be affordability, sustainability, and reliability. To assess this, during the IRP development I&M established a Balanced Scorecard that evaluated a wide range of potential portfolios against metrics that included: affordability, rate stability, sustainability impact, market risk minimization, reliability, and resource diversity. Additionally, I&M's Preferred Portfolio was developed with the understanding that significant resource decisions will need to be made in the future regarding the possibility to extend the operating life of the Cook Nuclear Plant.

Background

An IRP explains how a utility company plans to meet the projected capacity (*i.e.,* peak demand) and energy requirements of its customers. I&M is required to provide an IRP that encompasses a 20-year forecast planning period (in this filing, 2022-2041). This IRP uses the Company's current long-term assumptions for:

- customer load requirements – peak demand and hourly energy
- commodity prices – coal, natural gas, capacity, and emission prices
- existing planned supply-side resource retirement options
- supply-side alternative costs and performance characteristics – including fossil fuel, renewable generation, and storage resources

[1] I&M is part of American Electric Power (AEP), and AEP has set carbon emission reduction goals to achieve 80% reduction by 2030 from a 2000 baseline and net zero emissions by 2050. See AEPs-Climate-Impact-Analysis-2021.pdf (aepsustainability.com).

- transmission planning
- energy efficiency and demand-side management program costs and impacts

In addition, I&M considered the effect of environmental rules and guidelines including the potential cost associated with some form of future regulation of carbon emissions, during the planning period, while recognizing there is uncertainty as to the timing and form future carbon regulation may take.

To meet its customers' future capacity and energy requirements, I&M made certain assumptions regarding the continued operation of its existing fleet of generation resources for this IRP's Reference portfolio. Section 8.3 describes the sensitivities to those assumptions. Specifically, the two units at the DC Cook Nuclear Plant (Cook) are assumed to operate through the remainder of their current license periods (Unit 1 – 2034 and Unit 2 – 2037), although as the Company gets closer to the end of the license lives it does expect to explore future life-extension opportunities in greater detail. Rockport Unit 1 is assumed to operate through its committed retirement date of December 31, 2028, and Rockport Unit 2 is assumed to provide capacity through May 31, 2024.[2] The Company also assumes the continued operation of its owned run of river hydroelectric and solar plants. Generation resources purchased under long-term contracts are assumed to continue through the end date of the respective contracts.

Importantly, I&M operates within the PJM Interconnection, L.L.C. (PJM) Regional Transmission Organization (RTO), while most Indiana and Michigan utilities operate in the Midcontinent Independent System Operator, Inc. (MISO) RTO. As expected, each RTO has its own capacity planning process that results in different resource planning criteria and assumptions. For purposes of this IRP, the Company adheres to PJM capacity requirements.

In this IRP, the Company continues to model portfolios that not only add resources to meet its PJM capacity obligation, but also provide zero variable cost energy to enhance rate stability, reduce emissions and further diversify its generation portfolio.

I&M has analyzed various portfolios that would provide adequate supply and demand-side resources to meet its projected peak load obligations, and reduce or minimize costs to its customers, including energy costs, for the next twenty years. Following are the key components and inputs of I&M's 2021 IRP process:

Key Changes from 2018-2019 IRP

This IRP includes the following changes from the Company's last IRP:

- Updated Load Forecast
- Conducted All-Source Informational and Renewable Requests for Proposals (RFPs) to inform resource costs and performance
- Incorporated EIA resource characteristics for other supply-side resources
- Inclusion of T&D avoided costs with DSM resources

[2] Consistent with the Settlement Agreement approved in Cause No. 45546.

- Incorporated the 2021 Market Potential Study results that included an expanded approach in the MPS development stage leading to improved modeling for energy efficiency, demand response and distributed energy resources
- Engaged an outside party, Siemens PTI, to provide their own unique expertise and perspective, facilitate the Stakeholder engagement process, and support the modeling and development of the IRP report
- Incorporated recommendations from the Indiana Utility Regulatory Commission (IURC) Staff Director's February 12, 2021, Final Report on 2018 Integrated Resource Plans (Director's Report) and other reports and input from the Director and staff of both the IURC and the Michigan Public Service Commission on opportunities for continued improvement in the IRP process

IRP Process

The I&M 2021 IRP followed a 5-step structured and holistic approach to identify the Preferred Portfolio that best meets I&M's defined objectives over a wide range of potential future conditions. This included an All-Source Informational RFP to provide market-based pricing and a Market Potential Study (MPS) to inform the IRP process. This structured approach provided a comprehensive decision support tool to aid I&M in developing a long-term plan based on the current generation portfolio and the anticipated retirements of generation over the next twenty years. This long-term plan evaluates the need for additional resources and provides a resource portfolio that balances I&M's objectives.

The IRP process complies with regulations and reliability requirements, while also quantifying risks introduced by the market and regulatory environments, the risk of over-reliance on imports and/or exports, and the risk of supply disruptions. The process considered numerous new resource options across multiple portfolios and evaluated these portfolios across a wide range of metrics.

The steps followed in the development of the Preferred Portfolio are the following:

- **Determine Objectives and Key Metrics** – Portfolios are evaluated in terms of Affordability, Sustainability and Reliability. Balanced Scorecard metrics are then identified and used to measure and evaluate performance of the portfolios against the objectives. The Balanced Scorecard metrics the Company used in this process, with stakeholder input, included: affordability, rate stability, sustainability impact, market risk minimization, reliability, and resource diversity.

- **Create and Analyze Candidate Portfolios** – Computer program optimization modeling is used to identify an optimized, lowest cost portfolio based on a given set of inputs that constitute a future state of the electric system. These conditions are a unique combination of Scenarios and Sensitivities used to inform Candidate Portfolio development. This is followed by probabilistic analysis of each of the portfolios to determine its cost and performance metrics under hundreds of future state combinations of selected inputs including, for example, load, fuel, and new resource capital costs.

- **Balanced Scorecard and Report** – Detailed portfolio results are presented through a Balanced Scorecard that measures the objectives through a process that considers attributes in accordance with Stakeholder feedback, economic and load growth projections, as well as I&M input. From this final scorecard, I&M selects a Preferred Portfolio that best balances all of the metrics while also consider underlying risk. The result is the selection of a Preferred Portfolio.

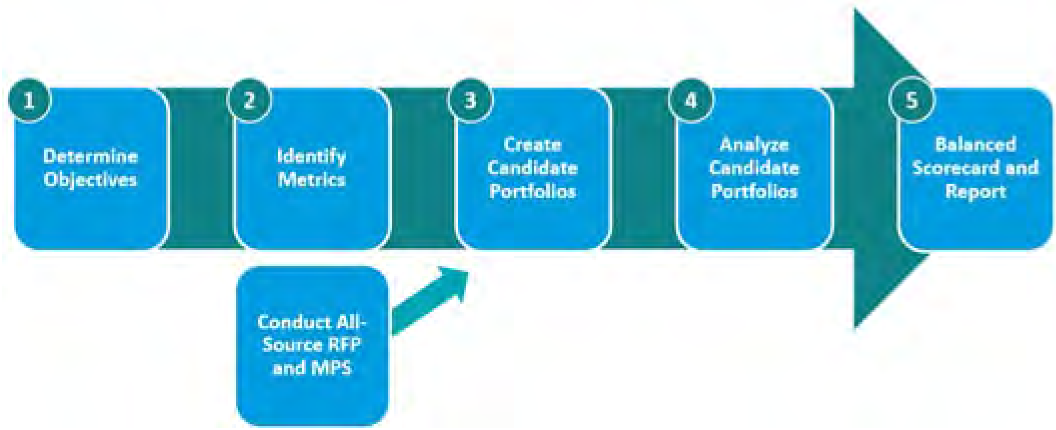


Figure 1. IRP Process

The electric utility industry is changing rapidly and is subject to a significant number of external factors that are largely outside its control and for which there are inherent limitations in modeling such factors and their potential risks. For example, during 2021 the industry experienced significant increases in fuel costs as well as supply chain and labor constraints that have impacted business operations and costs, and for which the future is uncertain. In addition, there remains a lot to be learned about the timing and impacts that growth in renewable resources, customer-owned generation, including implementation of the Federal Energy Regulatory Commission (FERC) Order 2222, and electrification of vehicles and the greater economy will have on load and resource requirements. Also, the focus of resource planning is shifting from the historical vertical approach to an integrated process that better coordinates and aligns the planning of generation, transmission, and distribution. As future IRPs are conducted, the Company expects continuous improvement in incorporating these dynamic and uncertain factors into the IRP process.

Stakeholder Participation Process

For this IRP, I&M considered multiple sources of feedback, including comments in the Director's Report, Stakeholder feedback, internal suggestions, as well as recommendations from the Siemens PTI consulting team. The Company engaged an experienced outside consultant, Siemens PTI, to bring their own experience, expertise, and collaboration tools to the stakeholder process. Both Siemens PTI and I&M promoted Stakeholder engagement during Stakeholder meetings despite the fact that all Stakeholder meetings had to be held virtually during this process due to the COVID pandemic. The goal was a Stakeholder engagement process focused on promoting transparency in the IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions to incorporate into the IRP process.

IRP Stakeholders included, but were not limited to, I&M residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, state agencies, and elected officials.

At the core of the process was a series of five Stakeholder Meeting Workshops.

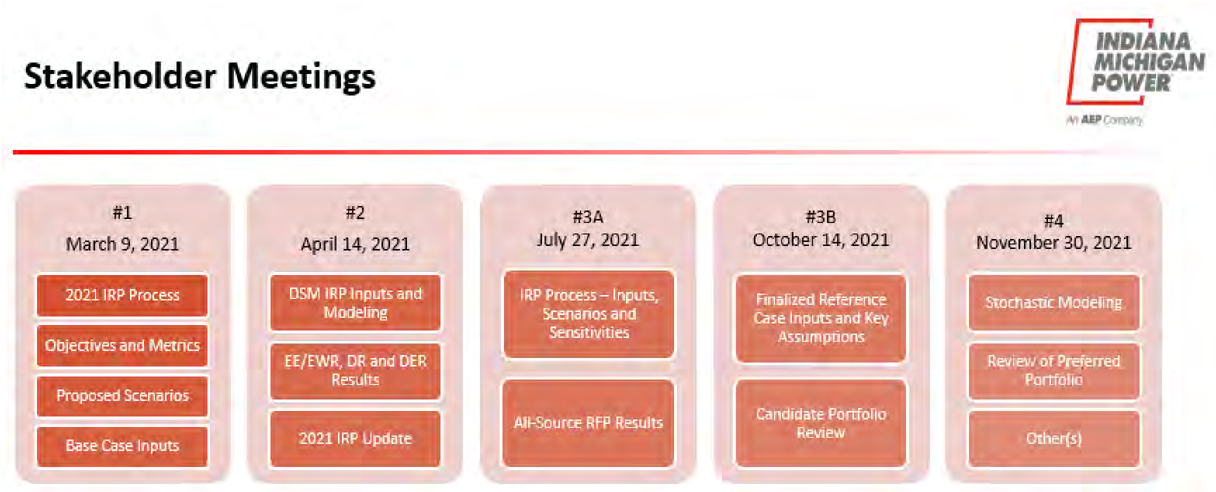


Figure 2. Topic Covered in Stakeholder Meetings

Each Stakeholder Meeting Workshop followed the same format.

- Introduction by I&M management
- Review of guidelines for the meeting and opportunities for Stakeholder engagement
- Focus Topics (different for each Stakeholder Meeting)
- Plans for Stakeholder Meetings and Data Provisioning
- Questions and Feedback at the end of each focus topic area
- Concluding remarks by I&M management

I&M and Siemens PTI worked diligently to have an open forum for Stakeholders to voice questions/concerns and make suggestions on the IRP analysis. During each Workshop, all participants could use the GoToWebinar tool to submit written questions or feedback. All written questions and feedback were recorded in the GoToWebinar tool. The results of these Question and Feedback sessions are included within each sessions' meeting minutes.

In addition to the core Stakeholder Meetings, a separate engagement process was developed for those "Technical Stakeholders" who desired to examine in more detail the underlying analysis performed during the IRP process. A process was designed to empower the Technical Stakeholders to participate in the technical analysis portion of this process by providing access and training on the modeling tool. The goal was to enhance collaboration and feedback beneficial to these Stakeholders.

Feedback was also received, and questions were answered via e-mail and with phone calls/meetings in between each session per request to ensure Stakeholder feedback was considered and incorporated in the development of the plan.

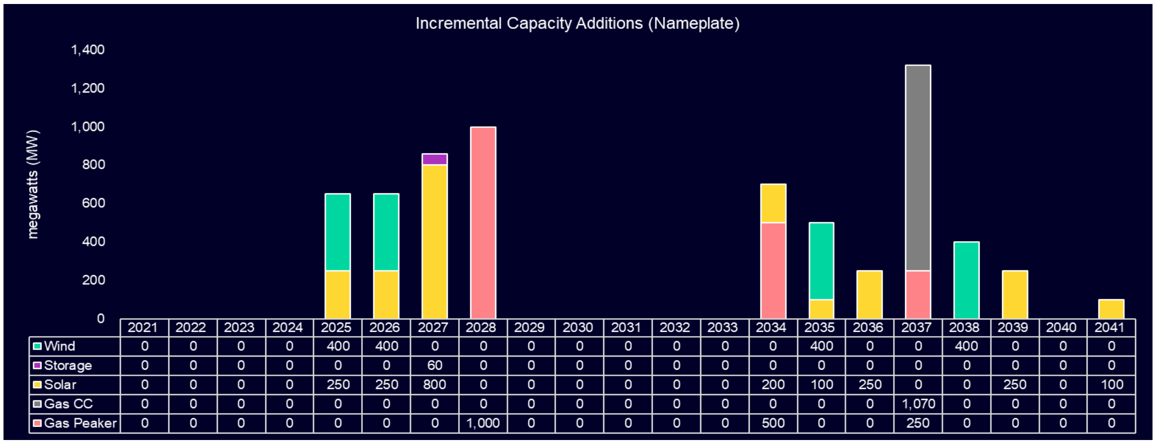
It is important to note that all feedback and suggestions were reviewed by both the IRP working team as well as I&M management. Throughout the process, I&M worked to consider all and include many of the suggestions into the IRP process. The final meeting was a preview of the Preferred Portfolio and a discussion of the completed analysis.

Summary of I&M's Resource Plan

I&M has prepared the Preferred Portfolio with a near-term plan, 2022 - 2028 and a long-term-indicative plan, 2029 – 2041. The near-term plan includes the resource additions that will be necessary for the Company to make from 2022 through 2028 and is inclusive of the Company's Short-Term Action Plan. The long-term-indicative plan includes the resource decisions that the Company will need to make from 2029 through the end of the planning period in 2041. The Company now has clarity regarding the Rockport Unit 1 retirement and the treatment of Rockport Unit 2 and the need for replacement capacity prior to 2028. Resource decisions beyond 2028 will ultimately be determined based on future decisions regarding the potential license extensions of the Cook Nuclear Plant, as well as other factors that will change over this time period. Because decisions have not been made regarding the license extensions and cost estimates have not been completed regarding the cost to extend the license, the Preferred Portfolio assumes Cook Unit 1 and 2 operations continue through 2034 and 2037, respectively.

With this significant decision regarding the potential license extensions at the Cook plant still uncertain, the Company was very intentional and thoughtful to structure the near-term plans in a manner that maintains optionality regarding the future decisions at the Cook Nuclear Plant. A significant consideration that the Company evaluated in the development of the Preferred Portfolio was the amount of energy being exported and potential future market risks. To maintain optionality regarding the future operations of the Cook Nuclear Plant, which is a significant emission-free energy producer, it was important for the Company to balance the need for near-term renewables and gas capacity additions with the energy position of the Company, while ensuring reliability. The resource additions included in the Company's Preferred Portfolio allow the Company to effectively begin its generation transition plan, replace the Rockport capacity, and maintain the option to extend the Cook Nuclear Plant Operating License. The Company's Preferred Portfolio achieves these three goals and performs well in the Balanced Scorecard against other Candidate Portfolios.

In addition to the existing resources, nameplate capacities of new supply-side resources in the Preferred Portfolio are shown in Figure 3 and include 1,600 MW of wind resources selected through 2038, 1,900 MW of stand-alone solar resources selected through 2041, the selection of hybrid paired solar + storage resources in 2027 of 60 MW storage / 300 MW Solar in 2027, 1,070 MW of Gas CC selected in 2037, and 1,750 MW of Gas CT resources through 2040.



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Wind	0	0	0	0	400	400	0	0	0	0	0	0	0	0	400	0	0	400	0	0	0
Storage	0	0	0	0	0	0	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	250	250	800	0	0	0	0	0	0	200	100	250	0	0	250	0	100
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	1,000	0	0	0	0	0	500	0	0	250	0	0	0	0

Figure 3. Incremental Capacity Additions (UCAP)

Figure 4 illustrates I&M's UCAP capacity position for the Preferred Portfolio and the PJM capacity obligation. The near-term plan includes both supply-side and demand-side resource additions in the Preferred Portfolio to meet the Company's near-term capacity needs. Resource additions through 2028 are sufficient from a capacity and energy needs perspective, with the exception of a short-term capacity deficit relative to the PJM minimum reserve requirement in PJM Planning Year 2024/2025. This deficit is currently expected to be approximately 314 MW, and will be filled with short-term PJM capacity purchases, as Rockport Unit 2 is transitioned out of the Company's regulated fleet and the Company transitions to a portfolio with more renewable resources. Short-term capacity needs are subject to further adjustments prior to the PJM Delivery Year based on evolving load forecasts and unit performance.

In the long-term plan between 2029 and 2041, utilizing an assumption for IRP modeling purposes that Cook Unit 1 and 2 will only operate until the end of the current license periods, the Preferred Portfolio includes an additional 800 MW of wind resources, 900 MW of solar, 1,070 MW of gas combined cycle, and 750 MW of gas peaking capacity. These resource additions will be modeled in future IRPs and updated as decisions are made regarding the Cook license extensions. The entire capacity plan is shown below:

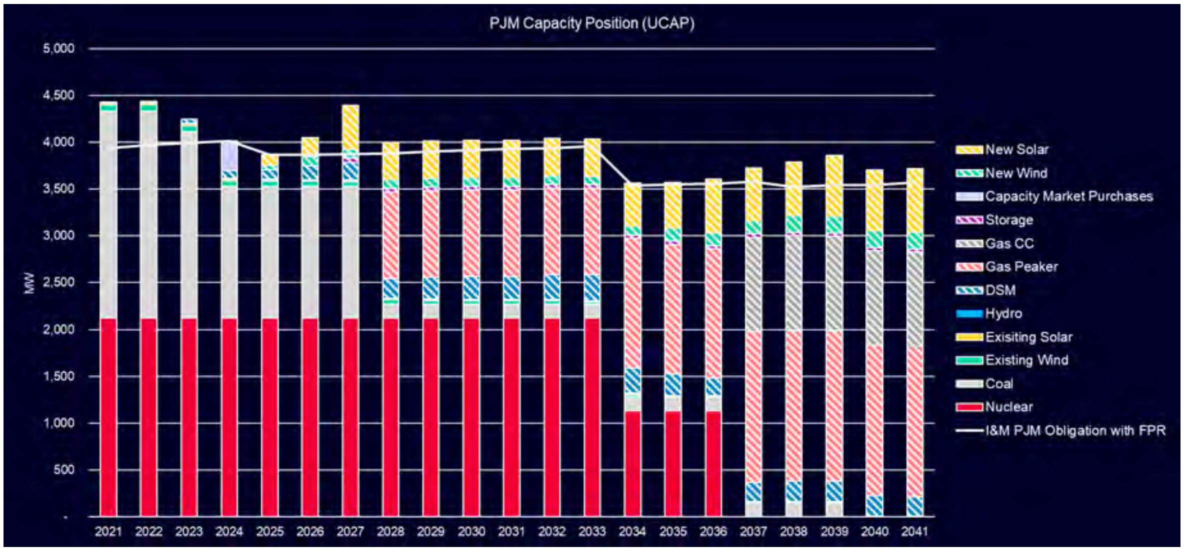


Figure 4. I&M's Preferred Portfolio - PJM Capacity Position (UCAP)

I&M conducted an expanded MPS that evaluated for a 20-year time horizon (2023-2042) the energy efficiency, demand response, and distributed energy resources potential separately for I&M's Indiana and Michigan jurisdictions. The MPS used the most granular load shape information available to improve the value realized from these measures. Energy Efficiency measure potential was developed using I&M's hourly load shape forecast data through an apportioning process based on the evaluation of which measures best aligned to load shapes according to I&M's customer segmentation and use profiles. This expanded approach in the MPS development stage helped improve energy efficiency measure attributes for the time-based value of these resources, thereby improving the level of energy efficiency benefits to be realized during the IRP modelling and optimization process.

Informed by the MPS, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 247 MW in 2033. Furthermore, the Preferred Portfolio includes incremental resources of 121 MW of demand response, 71 MW of distributed energy resources and 116 MW of conservation voltage reduction, based on the Company's MPS and internal analysis.

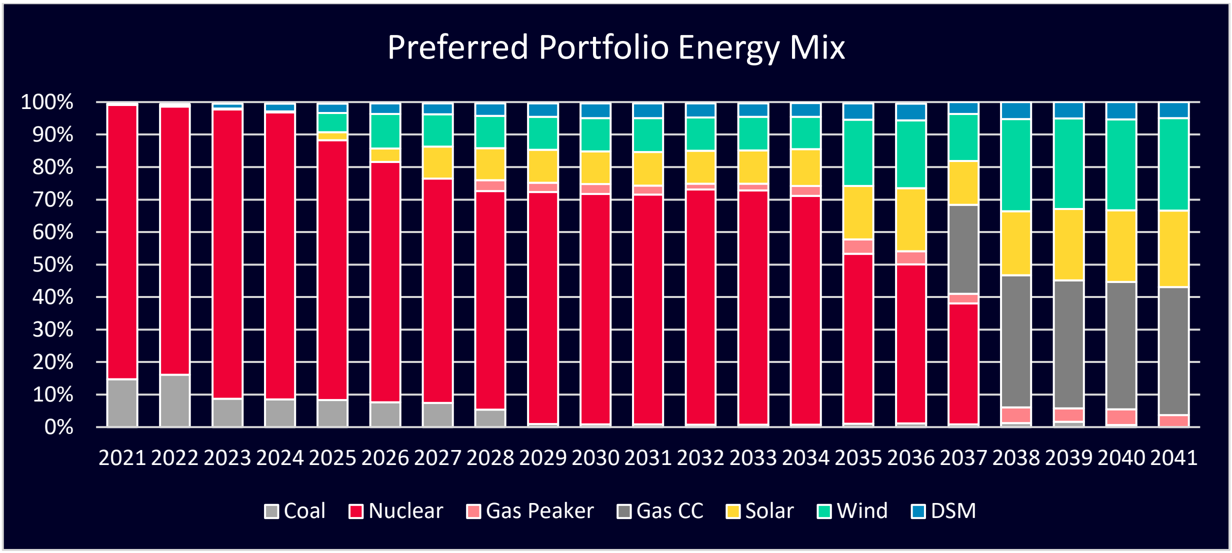


Figure 5: Preferred Portfolio Energy Mix

The forecasted energy mix by resource type contribution in the Preferred Portfolio over the planning period is illustrated in Figure 5. From an energy perspective, the Preferred Portfolio resources include the addition of renewable resources that produce higher levels of energy relative to their accredited capacity and DSM resources that serve to mitigate future risks related to fuel price uncertainty and potential sustainability related costs. Additionally, these resources include incremental dispatchable generating resources (CT) to support resource adequacy and reliability during the periods when renewable resources are not providing energy to meet the Company's load obligation.

I&M's Short-Term Action Plan

The I&M IRP is regularly reviewed as new information becomes available. I&M intends to pursue the following activities for the IRP Short-Term Action Plan:

1. Continue the planning and regulatory actions necessary to implement additional cost-effective DSM programs in Indiana and Michigan consistent with this IRP that identified the potential for increased levels of cost-effective EE.
2. Obtain the capacity needed for the PJM Planning Year 2024/2025 deficit (currently estimated to be about 314 MW in this IRP).
3. Issue an All-Source RFP in the first quarter of 2022 to seek resources to satisfy the 2025 and 2026 needs (in-service by the end of 2024 and 2025), which the Preferred Portfolio identified as 800 MW of wind and 500 MW of solar.
4. Issue an All-Source RFP in 2023 or 2024 to satisfy identified needs, targeting 2027 and 2028 renewables, storage, and gas additions (in-service by the end of 2026 and 2027), totaling 800MW of solar, 60 MW of storage as a hybrid resource, and 1,000 MW of gas peaking.
5. Initiate efforts to evaluate Cook relicensing costs.
6. Adjust this action plan and future IRPs to reflect changing circumstances, as necessary.

Conclusion

This IRP incorporated an extensive and thorough process that engaged Stakeholders through five public Stakeholder meetings and tested several Scenarios and many different Portfolios to arrive at a Preferred Portfolio.

The Preferred Portfolio performs well across a range of metrics that were used in the Balanced Scorecard. The Preferred Portfolio is the best performing portfolio across multiple measures on the Balanced Scorecard and provides several additional benefits to I&M customers and Stakeholders, including the following:

Affordability and Rate Stability:

- The Preferred Portfolio is among the lowest reasonable cost portfolios measured on both a 20-year and 10-year cost to serve load metric. The only comparable portfolios are the Cook 2050+ life extension portfolios, which do not include consideration of the capital investments required to extend the life of those facilities (will be evaluated further in future IRPs).
- The Preferred Portfolio has one of the lowest absolute values for the 95th percentile value of NPV cost to serve load. All portfolios share a similar upside risk. This translates into having one of the lowest risk of increases in cost across the portfolios.
- Resource type additions in the Preferred Portfolio are similar through 2028 to the portfolios that modeled Cook license extensions (Cook 2050+), resulting in a “no regrets” position for the next several years.
- The Preferred Portfolio includes dispatchable resources that can enhance opportunities for wholesale sales without overexposure to market risks.
- The Preferred Portfolio takes advantage of existing tax incentives for new wind, solar and hybrid solar resources.
- The Preferred Portfolio requires the lowest capital requirements during the near-term planning period, which also lowers the risk associated with the availability of acquiring the necessary resources.

Market Risk

- The Preferred Portfolio mitigates overreliance on market purchases and sales for capacity and energy throughout the forecast horizon.
- The Preferred Portfolio requires short-term PJM capacity purchases for capacity in 2024 to replace Rockport Unit 2 capacity.
- Market purchases and sales of energy are reasonable and there is less reliance on the spot energy market, with the Preferred Portfolio averaging 7.2% for purchases and 19.8% for sales over the forecast horizon.
- The Preferred Portfolio results in small amounts of surplus capacity over the forecast period
- The Preferred Portfolio avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

Sustainability:

- The Preferred Portfolio leads to a lower carbon future, achieving 76% reduction by 2041, when including CO_2 emissions for short-term and spot market purchases, from 2005 levels that did not include CO_2 emissions assumptions from short-term and spot market purchases. Excluding short-term and spot market purchase emissions estimates, the Preferred Portfolio realizes CO_2 emissions reductions of 82% by 2041.
- The Preferred Portfolio includes a substantial amount of renewable resources as it continues to transform its fleet.
- The Preferred Portfolio maintains the optionality for the Cook License Extensions which maintains the opportunity to extend the operations of a significant emission-free resource.
- The Preferred Portfolio provides potential opportunities for natural gas conversion to hydrogen fuel later in the planning period.
- The Preferred Portfolio significantly reduces the reliance on coal fired generation by 2029.

Reliability and Resource Diversity:

- The Preferred Portfolio includes additions that when added to the Company's current resources, provides a more diversified portfolio of supply-side and demand-side resources that will allow the Company to optimize the use of each resource type to ensure the reliable supply of electricity while also maintaining PJM capacity requirements and supporting resource adequacy.
- The Combustion Turbine (CT) resources provide flexible, fast ramping capabilities and can help mitigate risks associated with intermittent renewable resource additions.
- The Preferred Portfolio manages the reliance on market purchases and sales for capacity and energy purposes. In addition, it avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

In conjunction with the Company's Short-Term Action Plan, the Preferred Portfolio offers I&M significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Portfolio.

1 Introduction

1.1 Overview

This Report presents the 2021 Integrated Resource Plan (IRP or Plan) for Indiana Michigan Power Company (I&M or Company) including descriptions of assumptions, study parameters, and methodologies. The 2021 IRP process for the Company resulted in an integration of supply- and demand-side resources.

The goal of this IRP process is to develop a near-term plan (including a Short-Term Action Plan) and a long-term-indicative plan identifying the amount, timing and type of resources required to supply capacity and energy as part of the Company's obligation to ensure a reliable and economical power supply to its Indiana and Michigan customers.

In addition to developing plans for achieving reliability/reserve margin requirements as set forth by PJM and meeting I&M's obligation to ensure reliable and economical power supply to its customers, resource planning also impacts I&M's capital expenditure requirements, regulatory planning, environmental compliance, and other planning processes.

This Report covers the processes, assumptions, results, and recommendations required to develop the Company's IRP. It uses the best available information at the time of preparation, but changes that may affect its results can, and do, occur without notice. Therefore, commitments to specific resources and actions remain subject to further review and consideration.

1.2 Introduction to I&M

I&M is a multi-jurisdictional company serving both retail and wholesale customers located in the states of Indiana and Michigan (see Figure 6). Currently, I&M serves approximately 471,000 and 130,000 retail customers in the states of Indiana and Michigan, respectively. The peak load requirement of I&M's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. I&M's all-time highest recorded peak demand was 4,837MW, which occurred in July 2011; and the highest recorded winter peak was 3,952MW, which occurred in January 2015. The most recent (summer 2020 and winter 2020/21) actual I&M summer and winter peak demands at the time this process began were 3,970MW and 3,365MW, occurring on July 19, 2020, and February 17, 2021, respectively.

Figure 6: I&M Service Territory and Generating Locations

2 I&M's IRP Process

2.1 Overview of the IRP Process

The purpose of the IRP is to develop a set of supply- and demand-side resources ("Preferred Portfolio") that guides how I&M generates and supplies electricity in a way that balances affordability, sustainability, and reliability.

The I&M 2021 IRP followed a 5-step structured and holistic approach to identify the Preferred Portfolio that best meets I&M's defined objectives over a wide range of potential future conditions and included a Renewable RFP and an All-Source Informational RFP to include market-based pricing and a Market Potential Study (MPS) to inform the IRP process. This structured approach provided a comprehensive decision support tool to aid I&M in developing a near-term plan, 2022 - 2028 and a long-term-indicative plan, 2029 – 2041, based on the current generation portfolio and the anticipated retirements of generation over the next twenty years. This long-term plan evaluates the need for additional resources and provides a resource portfolio that balances I&M's objectives.

The IRP process, and associated modeling, complies with regulations and reliability requirements, while also quantifying risks introduced by the market and regulatory environments, the risk of over-reliance on imports and/or exports, and the risk of supply disruptions. The process considered an array of new resource options, including an updated Market Potential Study that included energy efficiency, demand-side management and distributed energy resources, renewable energy, battery storage and hybrid resources, such as paired storage and solar, gas resources, advanced technologies such as small modular reactors, etc.

The steps followed in the development of the Preferred Portfolio are illustrated in Figure 7 and are described in more detail in the following sections.

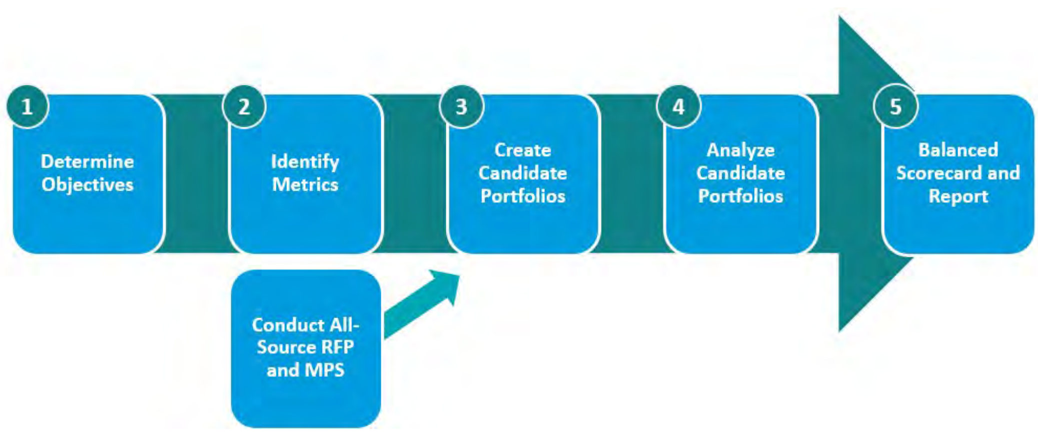


Figure 7. I&M IRP Process

Step 1: Determine Objectives: The initial step in the IRP Process is to determine the objectives that will be used to evaluate the various Candidate Portfolios. Candidate Portfolios are evaluated in terms of Affordability, Sustainability and Reliability.

Step 2: Identify Metrics: The second step in the IRP process is to assign metrics to the IRP objectives identified in Step 1. The metrics are used to measure and evaluate performance of the portfolios in the probabilistic simulations conducted in Step 4 of the IRP process.

Step 3: Create Candidate Portfolios: The third step in the IRP process is to create a set of optimized portfolios under a set of inputs that are informed by conditions. These conditions are a unique combination of Scenarios and Sensitivities used to inform Candidate Portfolio development.

Step 4: Analyze Candidate Portfolios: The fourth step in the IRP process is to conduct portfolio analysis to determine cost and performance metrics for each portfolio. As part of the current I&M IRP, the primary tool for portfolio analysis was a probabilistic (stochastics) analysis.

Step 5: Balanced Scorecard and Report: In the final step of the IRP Process, detailed portfolio results are presented through a Balanced Scorecard. The Balanced Scorecard incorporates each of the objectives and measures through a process that considers attributes in accordance with Stakeholder needs, economic and load growth projections, as well as I&M input. The result of Step 5 is the selection of a Preferred Portfolio.

2.2 Conduct a Renewable RFP and an All-Source Informational RFP

This IRP was informed by two RFP efforts.

In November 2020, I&M issued a Renewable RFP for 450 MW of solar and wind energy resources with optional battery energy storage systems, including both purchase and sale agreements and purchase power agreements. This RFP was solicited with an expectation of transacting although the Company chose not to proceed with responses received at that time.

Additionally, an All-Source Informational RFP was issued at the onset of the IRP process to obtain market information and near-term indicative pricing for a wide range of technologies.

The All-Source Informational RFP requested power supply and demand-side proposals for capacity and energy to meet the need of its customers. Understanding that the Informational RFP did not request firm pricing proposals with the intent to transact, the purpose of the Informational RFP was to identify viable resources in the marketplace available to I&M to meet the needs of its customers and gain better information on indicative pricing at the time the proposals were submitted.

I&M requested information from the marketplace for the following resource types:

- Dispatchable resources including Stand-alone Battery Energy Storage System
- Utility scale renewable resources, either stand-alone or paired with storage
- Load Modifying Resources
- Demand Response
- Distributed Generation

The Company evaluated the responses from the All-Source Information RFP to determine the project viability, reasonableness of proposed pricing, and other operating characteristics to determine an appropriate proxy to be used in the IRP process. The average delivered cost by resource informed the modeling and portfolio options. A summary of the All-Source Informational RFP and the Renewable RFP results were presented in Stakeholder Meeting #3A.

2.3 Develop a Market Potential Study

A Market Potential Study was conducted by GDS Associates and Brightline to evaluate the potential for future energy efficiency[3] (EE), demand response[4] (DR) and distributed energy resources (DER) resources in the 2021 I&M IRP and to support the IRP and DSM Planning for I&M. The Market Potential Study performed the following to develop inputs into the IRP Process and is further discussed in Section 7.7.1:

- An update of program costs and savings potential specific to each of I&M's service area in Indiana and Michigan over a 20-year time horizon (2023-2042).
- Primary market research, industry best-practice research, codes and standards research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities, to develop estimates of technical, economic, and achievable potential.
- Separate estimates of energy efficiency, demand response, and distributed energy resources potential were developed by I&M jurisdiction.

2.4 Objectives, Metrics and Scorecard Development

The IRP process is structured to enable a systematic and holistic planning analysis to identify the Preferred Portfolio that best meets all its objectives and design requirements over a wide range of market futures. The IRP Process is a time-tested five-step process, which results in a reliable and efficient approach to identifying future resource needs to meet the energy and capacity needs for I&M customers.

Beyond identifying a Preferred Portfolio, the IRP process aims to comply with all environmental regulations and reliability requirements enforced by various Local, State and Federal organizations. In doing so, the process is meant to identify portfolio vulnerabilities to market and regulatory risks and the risks of supply disruptions. As part of the IRP, I&M considered maintaining flexibility to respond to market changes as well as results from subsequent RFPs from the market. As such, the evaluation can be viewed as considering both existing and new resource options, including a diversified portfolio of supply - and demand- side options.

The resulting least cost portfolios developed by the resource optimization reflect a combination of market, regulatory and technology specified conditions. While least cost is an important objective, and a driver of the optimization routine, it is not the only objective that is important to this process. I&M has many important objectives including considerations for affordability, sustainability, market risk minimization, reliability, and resource diversity.

[3] Also referred to as energy waste reduction or EWR in Michigan.

[4] Also referred to as load management in Michigan.

The 2021 IRP is designed to evaluate ongoing changes and uncertainties in the market. As a result, I&M's IRP objectives are based on the need for a resource strategy that provides support for a series of near-term resource decisions while providing important directional insight into the long-term resources needs and key considerations to maximize the long-term potential value to its customers and communities. To that end, I&M identified six objectives for the Preferred Portfolio in the 2021 IRP that align with customer and corporate priorities, including customer affordability, rate stability, market risk minimization, sustainability impact, reliability, and resource diversity. As objectives are identified, it is important to keep in mind that tradeoffs must be considered. Table 1 provides more detail on these IRP objectives.

Table 1. I&M IRP Objectives

Objective Category	Objective	Objective Description
Affordability	Affordability	Meet energy and demand requirements of customers at an affordable cost that minimizes cost to serve load. Provide all customers with an affordable supply of energy.
	Rate Stability	Meet energy and demand requirements of customers with rate stability by providing a predictable, balanced, and diverse mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
	Market Risk Minimization	Avoid overreliance on spot market for energy and capacity purchases and sales, which could introduce excess risk for customers.
Sustainability	Sustainability	Ability to produce energy in a way that proactively reduces pollution and impact on surrounding neighborhoods and ecosystem. Provide environmentally responsible power, leading to a low carbon future.
Reliability and Resource Diversification	Reliability	Ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance with PJM capacity obligations.
	Resource Diversity	Mitigate the risk of overreliance on one type of resource. Operational flexibility to back up the resource for resource types that could become operationally or economically eclipsed.

2.5 Scorecard Metrics

In order to allow the analysis to compare portfolio performance across diverse scenarios and identify a Preferred Portfolio, metrics related to each of the objectives were defined and used to evaluate different portfolios and planning strategies in the IRP process. These metrics provide objective assessments of critical factors of each of the portfolios under different market conditions. An initial list of metrics was established early in the process and were reviewed in Stakeholder Meetings #1, #2, and #3B. Due to Stakeholder feedback received, three additional metrics were added including a Capital Investment Through 2028 metric, a 5-year Net Rate Increase CAGR metric and the Average # of Unique Generators. Additionally, the Market Risk Minimization metrics were modified from end of plan year values to average values over the planning period. The metric values for each portfolio were finalized in Step 4: Analyze Candidate Portfolios and result from the probabilistic (stochastic) analysis.

Table 2 below lists the metrics used in the evaluation of portfolios.

Table 2. IRP Objectives and Metrics

Objective Category	Objective	Metric
Affordability	Affordability	20-Year NPV Cost to Serve Load 10-Year NPV Cost to Serve Load
	Rate Stability	95th percentile value of NPV Cost to Serve Load Difference Between Mean and 95th Percentile 5 Year Net Rate Increase CAGR (2025-2029) Capital Investment Through 2028
	Market Risk Minimization	Avg. Purchases as a % of Load (2022-2041) Avg. Sales as a % of Load (2022-2041)
Sustainability	Sustainability	% Reduction of CO_2 (2005-2041)
Reliability and Resource Diversification	Reliability	Surplus Reserve Margin above FPR Requirement
	Resource Diversity	Average # of Unique Generators Average # of Unique Fuel Types

2.5.1 Affordability

As part of the Step 4 probabilistic modeling approach, each portfolio was subjected to 200 iterations of AURORA simulations which varied key drivers (e.g., coal prices, natural gas prices, carbon emission prices, peak and average load, and capital costs for a range of technologies). The affordability objective metrics used are the mean value of the 20-year Net Present Value Cost to Serve Load (NPVCTSL) and the 10-year NPVCTSL, expressed in million dollars. The NPVCTSL is a measure of all supply and demand-side related costs and revenues for each asset (capital cost, O&M, fuel, transmission costs, power and capacity purchases and sales) associated with the portfolio of assets over time. These costs are adjusted through a discount rate to ensure future costs are reflected in present year dollars, commonly known as a time value of money adjustment. In this way, very different portfolios can be compared on a common metric or value over a long-time frame.

2.5.2 Rate Stability

The rate stability objective metrics used are the 95th Percentile NPV of the Cost to Serve Load, Difference Between Mean and 95th Percentile, a 5-year Compound Annual Growth Rate (CAGR) of the Net Retail Rate Impact (“5-year CAGR metric”) and the Capital Investment Through 2028. The rate impact metrics were expanded based on stakeholder feedback. Specifically, the Capital Investments Through 2028 and 5-year Net Rate Increase CAGR were included because of feedback from stakeholders received during the public stakeholder sessions. As part of the probabilistic modeling approach performed in Step 4, once each portfolio was subjected to 200 iterations of AURORA simulations, a distribution was created of the NPV Cost to Serve Load portfolio costs. The 95th percentile (approximately two standard deviations above the mean value) is a commonly used benchmark to demonstrate the upper threshold of cost risk under widely varying market circumstances. The Difference Between Mean and 95th Percentile metric provides insight to the upside risk of the portfolio. The 5-year CAGR metric provides near-term insight to customer affordability and rate impacts of the resource additions in each Candidate Portfolio. I&M prepared a traditional, non-levelized calculation of the annual cost of service and the change in revenue requirements for the period of 2025-2029 when new near-term resources are added. Furthermore, the 5-year CAGR metric assumed the installed costs of all resource additions are capitalized and realization of federal tax benefits, except for energy efficiency resources that are reflected in cost of service or operations and maintenance expense. Finally, the Capital Investment Through 2028 metric identifies the near term investments needed for each portfolio.

2.5.3 Market Risk Minimization

The Market Risk Minimization objective metrics include a calculation of average annual energy sales and average annual energy purchases, each divided by the average annual load, and expressed as a percentage over the 20-year time horizon. The metric is meant to capture a measure of reliance on market sales and/or purchases by the resulting portfolios.

2.5.4 Sustainability Impact

The sustainability impact objective metric estimated direct GHG emissions of each generation type, measured in tons of carbon dioxide (CO_2). In addition to direct emissions from each asset, and to account for CO_2 emission from purchases imported from the market, I&M used the capacity expansion developed in the Reference Portfolio for PJM to estimate the carbon content of the market on an annual basis. The metric evaluates the reduction of direct CO_2 emissions plus estimated emissions from imports relative to 2005 levels that did not include emissions assumptions from short-term and spot market purchases.

Additionally, the Company included a table of estimated Lifecycle CO_2 emissions for all portfolios in Exhibit C-26.

2.5.5 Reliability

The reliability objective metric is the Surplus Reserve Margin above the PJM Forecast Pool Requirement (FPR). As base load units are retired and new technologies are being deployed, there is more of a reliance on intermittent resources (i.e., renewable energy) to provide energy and capacity needs. Portfolios balanced the addition of intermittent resources and their associated Effective Load Carrying Capability (ELCC) capacity contribution, as informed by PJM, to I&M's overall capacity obligation. Resource adequacy was inherently evaluated as part of this metric through the use of PJM's guidance on ELCC capacity contribution for intermittent resources along with Unforced Capacity (UCAP) ratings of flexible resources to meet capacity requirements.

2.5.6 Resource Diversity

For the resource diversity objective, the Company developed several portfolios that included a wide range of resource types and fuel sources. Resource diversity helps minimize risk to customers by providing a mix of resources to minimize the dependence on any one resource type to meet capacity and energy needs. As such, the metrics used to evaluate the resource diversity objective include

Number of Unique Generators in 2041 (a metric recommended by Stakeholders) and Number of Unique Fuel Types in 2041.

3 Reference Scenario and Alternative Scenarios Overview

3.1 Overview

After determining the objectives and metrics, the next step in Siemens PTI's five-step IRP process is to define the Reference Scenario and various alternative inputs for consideration in the alternative scenarios used during the selection of a Preferred Portfolio. For the 2021 IRP, a Reference Scenario and two alternative scenarios to inform portfolio development were identified following Stakeholder Meeting #1.

3.2 The Reference Scenario

The Reference Scenario is the most expected future scenario using base forecast assumptions. The existing generation fleet within the "Region" is largely unchanged apart from new units planned with firm certainty or under construction.

In the Reference Scenario, major drivers include:

- AEP's Long-term energy and demand forecast
- Coal prices remain relatively flat over the forecast horizon in constant dollars consistent with EIA reference
- Natural gas prices move upward in real dollars consistent with EIA reference
- Capital costs for new resources are downward sloping for fossil and wind resources and decline significantly for solar and storage resources
- Carbon regulations limiting CO_2 emissions will commence in 2028 and remain in effect throughout the forecast horizon

3.3 Alternative Scenarios

Alternative scenarios were identified to test resource selections against varying future market conditions. For this IRP, two alternative scenarios were ultimately discussed with Stakeholders and determined to proceed in the analysis, including the Rapid Technology Advancement (RTA) scenario and the Enhanced Regulation (ER) scenario. These Scenarios were also informed by the Michigan IRP Planning Parameters.[5]

3.3.1 Rapid Technology Advancement

The Rapid Technology Advancement scenario assumes increased technological advancements, favorable regulation and overall economies of scale that favorably impact renewable resource cost. The scenario assumes resulting technology costs for supply-side renewable and demand-side resources that are 35% lower for wind, solar, storage, energy efficiency and demand response technology costs compared to the Reference Scenario.

[5] https://www.michigan.gov/documents/mpsc/11-21-2017_MIRPP_Final_606706_7.pdf

In the Rapid Technology Advancement scenario, major drivers include:

- Technology cost reductions for DSM, renewables, and storage result in lower costs.
- Technological advancement and economies of scale contribute to greater potential for energy efficiency and demand response.
- Carbon regulations limiting CO_2 emissions commence in 2028 and remain in effect throughout the forecast horizon.
- Thermal generation retirements are driven by unit age-limits and announced retirements, consistent with Reference scenario.
- Fundamental drivers (load, commodity prices,) remain consistent with the Reference scenario.

3.3.2 Enhanced Regulation

The Enhanced Regulation scenario assumes increased environmental regulations covering natural gas, coal, and CO_2. Illustrative examples include a potential fracking ban and increases of carbon reduction targets.

In the Enhanced Regulation scenario, major drivers include:

- Natural gas, coal prices and CO_2 prices are increased to reflect enhanced regulation
- Technology costs for thermal and renewable units remain consistent with the Reference scenario.
- Thermal generation retirements are driven by unit age-limits and announced retirements, consistent with Reference scenario.
- Carbon regulations limiting CO_2 emissions will commence in 2025 and remain in effect throughout the forecast horizon.
- A summary of the relative outlooks for key market drivers across the Reference and Alternative Scenarios considered are presented in Table 3 below.

Table 3. Directional Relationship of Key Inputs Across Scenarios

Scenario	Load	Gas Price	Coal Price	CO2	Renewable and Storage Costs	EE / DR Cost
Reference	Base	Base	Base	Base	Base	Base
Rapid Technology Advancement	Base	Base	Base	Base	Low	Low
Enhanced Regulation	Base	High	High	High	Base	Base

3.4 Portfolio Development

Siemens PTI's five-step IRP process discussed in Section 2, aims to address the gap between resource needs and current resources within the construct of the previously identified Scenarios and is a combination of expert judgement coupled with robust industry leading tools. As such, optimization techniques, expert judgement, practical considerations, and Stakeholder input were used to identify a series of Candidate Portfolios ("Candidate Portfolios") to inform I&M and Stakeholders of the type, timing and amount of supply and demand-side resources.

3.4.1 Long Term Capacity Expansion (LTCE) Assessments

Given the various assets and resources that can satisfy this expected gap, a process, supported by robust modeling and tools are needed to sort through the diverse mix of potential resource combinations and return an optimum solution. AURORA is the primary modeling application used by Siemens PTI for identifying and analyzing portfolios that address the gap between resource needs and current available resources. The model uses hourly chronological dispatch over a 20-year period which helps to better evaluate intermittent and storage resources.

The long-term capacity expansion functionality within AURORA was used to develop least cost optimized portfolios based on the given sets of market input assumptions and portfolio requirements. The LTCE function drives build, retirement and purchase decisions for the resulting portfolios.

3.4.2 Resource Models – AURORA

AURORA was used as the primary tool to develop two models for use, including: 1) I&M's Fundamental Forecast, and 2) Siemens Portfolio Construction and Risk Assessment. AURORA is an industry standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a state of the art, mixed integer programing approach ("MIP") to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other Stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices, and assess detailed impact of regulations and market changes affecting the electric power industry. Key inputs to the model include load forecasts, power plant costs and operating characteristics (e.g., heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates as well as capital costs. The model assesses the potential performance, fixed and variable O&M costs, and capital costs of prospective and existing generation technologies and resources, and makes resource addition and retirement decisions for economic, system reliability, and policy compliance reasons on a utility system, regional and nationwide scale. Outputs of the model include plant generation, gross margin, emissions, and a variety of other metrics.

Siemens PTI has used AURORA for well over 15 years as its primary model for asset valuation, power market forecast, and IRPs. The model is equipped to analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Siemens PTI has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic volatility in key market drivers and cross relationships between different market drivers. Siemens PTI has also developed modules to simulate the different operating characteristics of ISO/RTO regions across the country. For this reason, it is one of the most comprehensive, reliable, and flexible tools in the market for conducting IRPs. Siemens PTI has successfully conducted numerous IRPs for many utilities across the country, including several utilities in IN and MI. AURORA has gained wide acceptance among electric utility executives, Stakeholder groups, and regulatory commissions.

3.4.3 Portfolio Construction

Reference and Candidate Portfolios were developed utilizing AURORA's LTCE modeling for the Reference Scenario, Rapid Technology Advancement Scenario, and the Enhanced Regulation Scenario by optimizing resources based on lowest cost, within the model parameters.

In addition to the Reference Portfolio, additional portfolios were identified to specifically test alternative resource strategies. These included defined portfolios in the Company settlement agreements along with portfolios identified by I&M to evaluate resource selections related to different future assumptions pertaining to the Cook nuclear unit life extension as well as evaluating solutions with high amounts of renewable resources. Table 4 summarizes the portfolios evaluated in Step 3 of Siemens PTI's five-step process to identify Candidate Portfolios to analyze in Step 4.

Table 4. Reference and Candidate Portfolios

Scenario Name	Portfolio Name	Description
Reference	Reference Case (Original)	Rockport Unit 1 (2028) Rockport Unit 2 (2024) and Cook (2034, 2037)
Reference	Rockport 1 2024	Rockport Unit 1 Early Retirement (2024)
Reference	Rockport 1 2025	Rockport Unit 1 Early Retirement (2025)
Reference	Rockport 1 2026	Rockport Unit 1 Early Retirement (2026)
Reference	Cook 2050+	Cook Unit 1 and Unit 2 License Extensions (beyond 2034 and 2037)
Reference	Cook 2050+ and No Gas	Cook Unit 1 and Unit 2 License Extensions and No Conventional Gas
Reference	Expanded Build Limits	Expanded Cumulative Build Limits on Renewable Energy and Storage
Reference	Reference' ("Prime")	Reference Case (Original) with an Import and Export Limit at ~30% of I&M Load
Rapid Technology Advancement	Rapid Technology Advancement	35% Reduction in Renewable, Storage and EE Costs
Enhanced Regulation	Enhanced Regulation	Increased Environmental Regulations Leading to High Gas, Coal and CO_2 Prices
Reference	Rockport 1 2024 N2G	Rockport Unit 1 Early Retirement (2024) Replacing SEA with Net to Gross EE Bundle Savings
Reference	Rockport 1 2026 N2G	Rockport Unit 1 Early Retirement (2026) Replacing SEA with Net to Gross EE Bundle Savings
Rapid Technology Advancement	Rapid Technology Advancement N2G	Rapid Technology Advancement (RTA) Replacing SEA with Net to Gross EE Bundle Savings
Reference	Reference with No Renewable Limits	Removed cumulative Build Limits on Renewable Energy and Storage

These portfolios were evaluated in the Step 4: Candidate Portfolio analysis to inform the identification of the Preferred Portfolio. Figure 8 illustrates the portfolio screening process defined as part of the analysis.

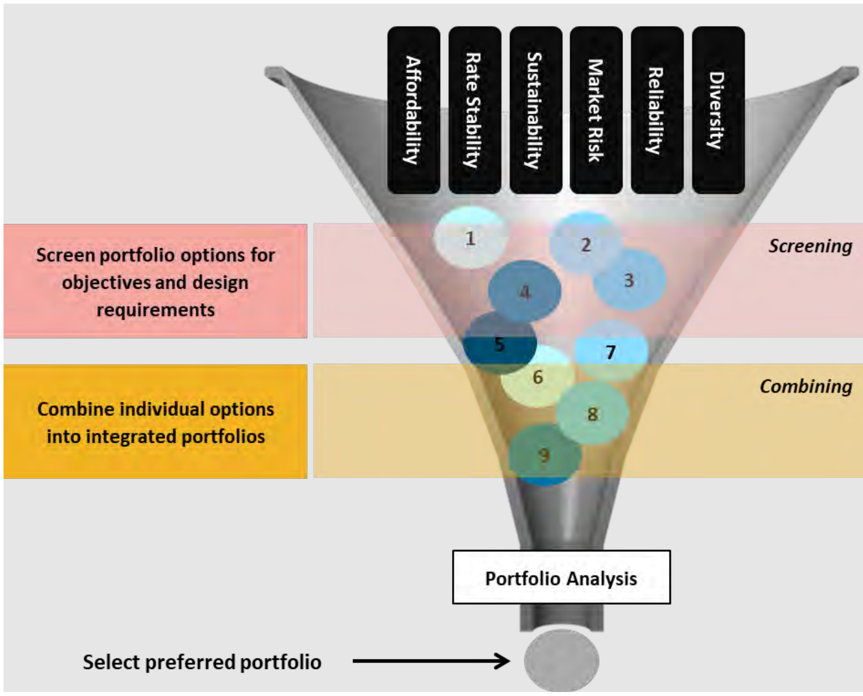


Figure 8. Structured Portfolio Selection Process

3.5 Portfolio Performance (Probabilistic / Stochastic Modeling)

Step 4 of Siemens PTI's five-step process included probabilistic modeling for each Candidate Portfolio to assess how well each portfolio performs under a range of market, technology, and regulatory uncertainties. Probabilistic modeling incorporates several market variables and probability distributions into the analysis. The approach allows for the evaluation of a portfolio's performance over a wide range of market conditions. The portfolio results of the probabilistic modeling inform the metrics used on the Balanced Scorecard, and thus each metric is a representation of over 200 unique AURORA results.

Probabilistic modeling begins with the development of 200 sets of future pathways for coal prices, natural gas prices, carbon prices, peak and average load and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period, typically over 2,000 times. A stratified sampling in the runs is taken, which allows the sample set to be reduced to 200 iterations. These 200 iterations of each stochastic variable are then loaded as inputs to the AURORA dispatch model. These inputs thus allow for the testing of each portfolios' performance across a wide range of market conditions.

All portfolios identified above were subjected to each of the 200 iterations using AURORA in dispatch mode, whereby the I&M portfolio of resources is held constant while the buildout in the surrounding PJM region could change within the AURORA model under each set of market conditions.

3.6 Balanced Scorecard

The stochastic analysis (based on the probabilistic modeling) of each of the portfolios was summarized through the Balanced Scorecard. The Balanced Scorecard compares the performance of each Candidate Portfolio against the Objectives and Metrics defined in the initial steps of the IRP planning process described in Section 2.5, providing insights to the differences between Candidate Portfolios.

There were several steps in the process of creating the Balanced Scorecard results:

- The first step was to develop the input distribution for each of the major market and regulatory drivers. Siemens PTI developed this process internally and it includes average and peak load growth and shape, natural gas prices, coal prices, carbon prices and technology capital costs. The approach for developing the input distributions included considering historic volatility of each factor and was further informed by EIA and subject matter experts.
- The second step was to run a probabilistic model (Monte Carlo) which selected 200 possible future states over the 20-year study planning period.
- Each Candidate Portfolio was then run through a simulated dispatch for the 200 possible future states using the AURORA production cost model. The process assumes I&M's Candidate Portfolio remains constant but allows for builds and retirements throughout the region (PJM) to occur based on economic criteria. As a result, I&M generation, costs, emissions, revenues, and all other metrics are tracked across all 200 iterations and presented as a distribution.
- From the simulated dispatch set of results described above, metrics described in Section 2.5 were calculated for each portfolio.
- Finally, these metrics were populated into the Balanced Scorecard and served as the basis for evaluation. The results of the analysis for the Candidate Portfolios are discussed in Section 8 Portfolio Development and Evaluation.

3.7 Identification of the Preferred Portfolio

The identification of the Preferred Portfolio is informed from the results of the Candidate Portfolios and how they met multiple objectives in the Step 4 analysis. The Preferred Portfolio is a product of complex analysis, expert opinion and a balanced assessment of computer results and is discussed in Section 9.

4 Public Stakeholder Participation Process

4.1 Public Participation Process

For this IRP, I&M conducted an extensive and thorough Public Participation Process. I&M considered multiple sources of feedback, including comments in the Director's Report, Stakeholder feedback, internal suggestions, as well as recommendations from the Siemens PTI consulting team. Care was taken to promote Stakeholder engagement even though all Stakeholder meetings were held virtually during this process due to the COVID-19 pandemic. The goal was a Stakeholder engagement process focused on promoting transparency in the IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions to incorporate into the IRP process.

As a result, Stakeholders have had the opportunity to provide feedback on virtually all areas of the IRP, including but not limited to the following:

- Establishing objectives of the IRP.
- Identification of metrics to be used in evaluating objectives.
- Review of inputs and key assumptions.
- Identification of alternative scenarios and sensitivities to generate a diverse range of potential Candidate Portfolios.
- Analysis of the Candidate Portfolios through the Stochastic Modeling process.
- Creation of the Preferred Portfolio.

I&M's objectives for Stakeholder engagement included:

- **Listen:** Understand concerns and objectives by providing a forum for Stakeholder feedback at key points in the Integrated Resource Plan process to inform I&M's decision making.
- **Inform:** Increase Stakeholder understanding of the Integrated Resource Plan process, key assumptions, and the challenges facing I&M and the electric utility industry through discussion, answering, and asking questions and being transparent in the process.
- **Consider:** Review all Stakeholder input and carefully consider this feedback at key points in the Integrated Resource Plan process to inform I&M's decision making.

IRP Stakeholders included, but were not limited to, I&M residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups and elected officials.

At the core of the process was a series of five public Stakeholder Meeting Workshops. Figure 9 below lists the topics covered in each stakeholder meeting.

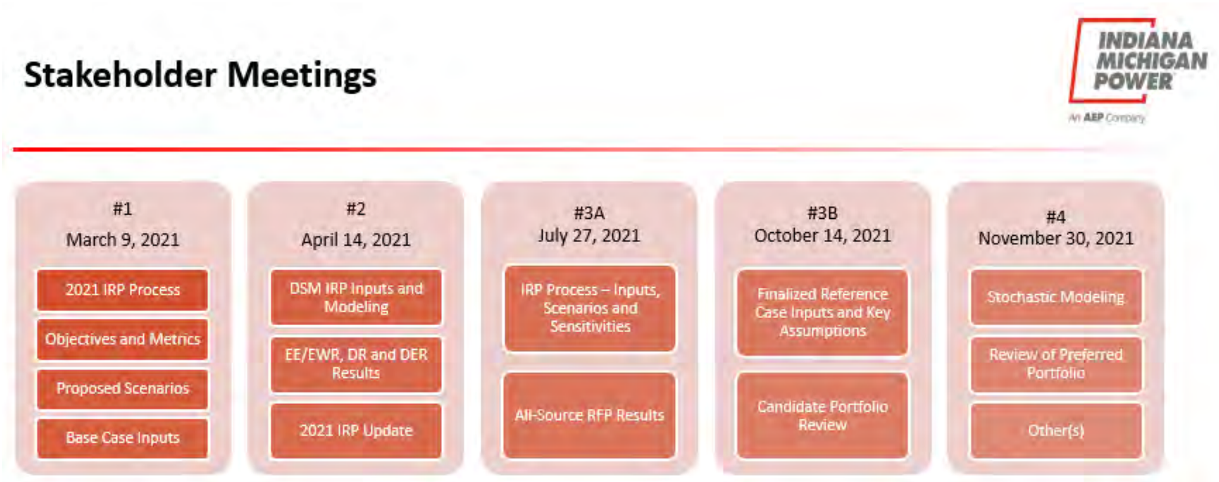


Figure 9. 2021 Stakeholder Meeting Workshops

Meeting materials of each Stakeholder meeting can be found in IRP Appendix Volume 4 and at https://www.indianamichiganpower.com/community/projects/irp/. All Stakeholder meetings were held via webinar utilizing the GoToWebinar meeting tool.

Concurrent with the Stakeholder meetings described above, the Company managed an IRP website where Stakeholders had an opportunity to submit questions and provide feedback directly for further consideration throughout the process. This provided Stakeholders an ongoing and continuous opportunity to engage with I&M during the IRP process. A summary of the Stakeholder meetings described above are found in Appendix Volume 4, including the presentations, meeting minutes and a full list of the written Stakeholder questions responded to by the Company. In total, I&M answered more than 275 questions from stakeholders during the IRP stakeholder process.

The IRP Stakeholder meetings had a robust attendance with an average of more than 75 participants attending each of the five Stakeholder Meetings. Highlights of each Stakeholder meeting are summarized below in Section 4.2.

Each Stakeholder meeting followed the same format.

- Introduction by I&M management
- Review of guidelines for the meeting and opportunities for Stakeholder engagement
- Focus Topics (different for each Stakeholder Meeting)
- Plans for Stakeholder Meetings and Data Provisioning
- Questions and Feedback at the end of each focus topic area
- Concluding remarks by I&M management

I&M worked diligently to have an open forum for Stakeholders to voice questions/concerns and make suggestions on the IRP analysis. Each I&M Stakeholder meeting was opened by a member of the I&M senior management team. I&M senior management, I&M subject matter experts, and expert consultants actively participated in each meeting to help address Stakeholder questions/concerns.

During each Workshop, all participants could use the GoToWebinar tool to submit written questions or feedback. All written questions and feedback submitted by the participants were saved in the GoToWebinar tool. Participants were also able to ask questions or give feedback orally. The results of these question and feedback sessions are included in each Stakeholder Meeting minutes.

It is important to note that all feedback and suggestions were reviewed by both the IRP working team as well as I&M management. Throughout the process, I&M worked to include many of the suggestions into the IRP process, analysis and results.

4.2 IRP Stakeholder Meeting Discussions

Each IRP Stakeholder Meeting coincided with the ongoing five-step IRP process described in Section 2. This intentional coordination was to ensure Stakeholders were informed of the available information at each step.

In the first Stakeholder meeting, I&M presented the IRP process to be followed for the development of the 2021 Integrated Resource Plan. During this meeting, the framework for the creation of Scenarios and Sensitivities was presented, along with the identified IRP Objectives and the proposed metrics. Stakeholders were encouraged to provide feedback related to scenario conditions or potential additional sensitivities that would allow a broad and diverse review of potential Candidate Portfolios. Additionally, Stakeholders were introduced to the Balanced Scorecard method planned for use to evaluate portfolio results. Through the GoToWebinar tool, we received questions and feedback during each topic session, which allowed the meeting facilitators to address questions during the Questions and Feedback sessions that followed each major section of the agenda. The Company received feedback in several areas related to the Balanced Scorecard, proposed Scenarios, and Metrics that influenced the refinement of decisions at this junction in the IRP process. The feedback received during this discussion focused on using a Balanced Scorecard approach, the method for which the Company would assess emissions, the proposed High Market variant Scenario and the proposed diversity metric.

A thorough discussion was held during the meeting related to the number of Scenarios evaluated in this IRP, resulting in a recommendation to not include High Market variant Scenario in order to eliminate confusion when comparing results and with the understanding that Step 4 in the IRP process will utilize probabilistic analysis that will provide the opportunity to consider a variation of load futures, including a high load future much like that intended for the High Market variant Scenario. Additionally, there was Stakeholder feedback related to the proposed Diversity metric, with suggestions for additional metrics.

With the feedback and engagement received from Stakeholder meeting 1, the Company continued its evaluation of the proposed Scenarios, Sensitivities, and the associated Metrics to ensure the IRP Process would address the IRP Objectives and comply with all regulatory requirements. The feedback during this meeting was also considered throughout the entire course of this IRP, with a consistent reference back to the interest expressed in both the Scenarios and the associated Metrics. As will be discussed later in this report, the Company updated its analysis to include two additional metrics: 1) a diversity metric that incorporated feedback from the Stakeholders, and 2) an additional Rate Impact metric.

Stakeholder Meeting 2 was focused on Energy Efficiency and Demand Side resources. In this meeting, the Company, along with the GDS Team and Siemens PTI, presented its plan to utilize the information from the 2021 Market Potential Study, including the methods being considered for modeling DSM resources and the development of EE Bundles to support an efficient IRP modeling approach for these resources.

The feedback received from this meeting related to assessment and selection of the EE bundling method used in this IRP resulted in further coordination and review with the GDS Team. The original proposal for using a Value-Based Approach was replaced with a method preferred by Stakeholders to group measures into sector-level portfolios for inclusion in the IRP modeling.

The Company also spent considerable time assessing its approach toward the modeling of EE resources. This effort included the Company reaching out to several peer Utilities to understand their approach to capturing EE benefits in the forecasted load obligations. This effort provided an understanding of alternative methods in use and their perspectives on the subject. In summary, the Company found that while methods varied among peer Utilities, the net adjustment to the total EE impact were statistically equivalent. These results were presented in Stakeholder Meeting 3a.

Stakeholder Meeting 3 was originally intended to discuss the key IRP inputs as well as Candidate Portfolios identified to analyze for the purpose of informing the Company for the identification of its Preferred Portfolio. With the work related to modifying the IRP assumptions and inclusion of additional portfolios to model related to the settlement agreement in Cause No. 45546, the Company adjusted the original plan and divided this meeting into two meetings. Meeting 3a focused on key model inputs and the Reference Scenario development. Stakeholders were also presented with the results of the All-Source Informational RFP and the Renewable RFP that informed the IRP. Stakeholders provided input into portfolio development, which helped to provide a wide range of portfolios, including an all-renewables portfolio by 2050, and alternative retirement and use scenarios for the Rockport Units 1.

EE modeling was further discussed during Stakeholder meeting 3a. As part of the settlement agreement in Cause No. 45546, further discussions were held with several Stakeholders related to the IRP assumptions related to Rockport Unit 2 and the development of additional Sensitivities to evaluate the effect of applying a Net to Gross (NTG) Energy Efficiency adjustment to the EE bundle potential savings. This required an update to the modeling to reflect new assumptions for this IRP. The Company discussed with and presented to Stakehlders the additional portfolio analysis and associated EE modeling inputs over the course of the two additional meetings.

Stakeholder Meeting 3b presented the Candidate Portfolios being analyzed. The Company received feedback from various stakeholders on several topics related to the modeling inputs and dynamics. Several questions related to the Candidate Portfolio modeling results and the associated analysis were further reviewed following the meeting. This included feedback related to the proposed Rate Impact metric and energy balance and exports.

Following this meeting, the Company concluded its development of an additional method to analyze rate impacts on a non-levelized basis (note this topic was also raised during the 1st Stakeholder meeting.) This was a new approach to traditional methods for evaluating rate impacts in the IRP. Additionally, the Company, along with Siemens PTI, further evaluated feedback received after the meeting related to the energy exports seen in the various Candidate Portfolios.

Stakeholder Meeting 4 was held in late November to review the results of the Candidate Portfolio analysis and the Company's Preferred Portfolio. In this meeting, the Company discussed the Candidate Portfolio Balanced Scorecard metrics and how the stochastic results informed the development of the Preferred Portfolio. The Company presented its Preferred Portfolio with specific actions in its near-term plan to meet its overall objectives, and explained how the Preferred Portfolio retains long-term optionality around the Cook Plant extension until the necessary re-licensing studies are performed. See Section 9 to this Report for a more detailed explanation of the presented Preferred Portfolio.

4.3 Additional Stakeholder Engagement

4.3.1 All-Source Informational RFP review

As part of I&M's efforts to conduct an All-Source Informational RFP, a meeting was facilitated by Siemens PTI on the process for this effort. The Stakeholders were presented the draft documents associated with the RFP prior to the release of the final response documents to solicit Stakeholder feedback. The purpose of the All-Source Informational RFP was to provide current, market-based cost and performance data inputs to the IRP process. This Stakeholder meeting was conducted on

April 9, 2021. The summary of this review was presented to Stakeholders in Stakeholder Meeting 3a.

4.3.2 Technical Stakeholders

In addition to the core Stakeholder Meetings, a separate engagement process was developed for the "Technical Stakeholders" who desired to examine in more detail the underlying analysis performed during the IRP process. The following three-stage process was designed to empower the Technical Stakeholders to participate in the technical analysis portion of this process resulting in enhanced collaboration and feedback beneficial to all Stakeholders.

Stage 1: Preparation for use of the AURORA Tool: Late June – Early September

Objective: Technical Stakeholders to be equipped with the AURORA application and complete any training required to be productive with the application.

During Stage 1 Technical Stakeholders were asked to:

- Install the AURORA Software
- Attend the AURORA Technical Conference (June 24)
- Utilize any training resources available to prepare for use of the AURORA application

To begin the process with the Technical Stakeholders, I&M and Siemens PTI hosted the "AURORA Technical Conference" on June 24, 2021. The purpose of this session was to provide a technical overview of the AURORA production cost modeling tool. Presentations were made by Deborah Austin-Smith, Director of Customer Service at Energy Exemplar (the owner of the AURORA application) and Mike Korschek of Siemens PTI. An agenda and presentation outlining the topics discussed are included in the Appendix F

Stage 2: Production of I&M IRP Inputs and Key Assumptions – November

Objective*: *Facilitate the review of the data and assumptions used within the AURORA tool. The assumptions and input data will be provided in Excel format and would be made available for download from a secure site maintained by Siemens PTI.

Three separate parties requested access to the IRP Inputs and Key Assumptions workbook. These parties completed the execution of a Non-Disclosure Agreement and were granted access to the data in November. In addition, a meeting was held on December 9, 2021, with Technical Stakeholders who had executed a Non-Disclosure Agreement to review the IRP Inputs and Key Assumptions and answer any questions.

Stage 3: Production of Reference Scenario AURORA database –February 2022

Objective: To provide the ability to verify model inputs and assumptions, re-produce the dispatch simulation results for the Reference Scenario and provide the ability for the Technical Stakeholder to analyze alternative dispatch simulation scenarios and sensitivities.

Siemens anticipates posting the I&M AURORA model on the secure website in late February 2022.

4.3.3 Additional Stakeholder Input

In this IRP, the Company also incorporated several terms associated with the Settlement Agreement approved in IURC Cause No. 45546. This included an adjustment to key inputs related to the modeling of Rockport Unit 2 and the inclusion of additional modeling portfolios to evaluate the effects of utilizing an alternative Energy Efficiency adjustment factor as well as a specific review meeting with the primary Stakeholder requesting the additional portfolios modeled.

Additionally, the Company managed an IRP website where Stakeholders had an opportunity to submit questions directly for further consideration throughout the process. A summary of the Stakeholder Meetings described above are found in Appendix Volume 4, including the presentations, meeting minutes and a full list of the written Stakeholder questions responded to by the Company.

5 Load Forecast and Forecasting Methodology

5.1 Summary of I&M Load Forecast

The I&M load forecast was developed by AEP's Economic Forecasting organization and completed in June 2021.[6] The final load forecast is the culmination of a series of underlying forecasts that build on each other. In other words, the economic forecast provided by Moody's Analytics is used to develop the customer forecast which is then used to develop the sales forecast which is ultimately used to develop the peak load and internal energy requirements forecast.

Over the next 20-year period (2022-2041),[7] I&M's service territory is expected to see population and non-farm employment growth of 0.0% and 0.4% per year, respectively. Not surprisingly, I&M is projected to see customer count growth at a similar rate of 0.1% per year. Over the same forecast period, I&M's retail sales are projected to grow at 0.3% per year with stronger growth expected from the industrial class (+0.46% per year) while the residential class experiences 0.3% CAGR and the commercial class remains relatively flat over the forecast horizon. Finally, I&M's internal energy and peak demand are expected to decrease at an average rate of 0.5% and 0.3% per year, respectively, through 2041.

5.2 Forecast Assumptions

5.2.1 Economic Assumptions

The load forecasts for I&M and the other operating companies in the AEP System incorporate a forecast of U.S. and regional economic growth provided by Moody's Analytics. The load forecasts utilized Moody's Analytics economic forecast issued in January 2021. Moody's Analytics projects moderate growth in the U.S. economy during the 2022-2041 forecast period, characterized by a 2.1% annual rise in real Gross Domestic Product (GDP), and moderate inflation, with the implicit GDP price deflator expected to rise by 2.1% per year. Industrial output, as measured by the Federal Reserve Board's (FRB) index of industrial production, is expected to grow at 1.5% per year during the same period. Moody's projects regional employment growth of 0.4% per year during the forecast period and real regional income per-capita annual growth of 1.7% for the I&M service area.

5.2.2 Price Assumptions

The Company utilizes an internally developed service area electricity price forecast. This forecast incorporates information from the Company's financial plan for the near term and the U.S.

[6] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of connected load, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

[7] 20-year period begins with 2022, while 2021 is six months actual and six months forecasts.

Department of Energy (DOE) Energy Information Administration (EIA) outlook for the East North Central Census Region for the longer term. These price forecasts are incorporated into the Company's energy sales models, where appropriate.

5.2.3 Specific Large Customer Assumptions

I&M's customer service engineers frequently are in touch with industrial and commercial customers about their needs and activities. From these discussions, expected load additions or deletions are relayed to the Company.

5.2.4 Weather Assumptions

Where appropriate, the Company includes weather as an explanatory variable in its energy sales models. These models reflect historical weather for the model estimation period and normal weather for the forecast period.

5.2.5 Energy Efficiency (EE) and Demand Side Management (DSM) Assumptions

The Company's long term load forecast models account for trends in EE both in implicit historical data as well as the forecasted trends in appliance saturations resulting from various legislated appliance efficiency standards (Energy Policy Act of 2005 [EPAct], Energy Independence and Security Act [EISA] of 2007, etc.) modeled by EIA. In addition to general trends in appliance efficiencies, the Company also administers and implements multiple DSM programs that the Commissions approve as part of its DSM portfolio. The load forecast utilizes the most current DSM programs, which either have been previously approved by or are pending before the Commission at the time the load forecast is created to adjust for the impact of these programs. For this IRP, DSM programs through 2022 have been embedded into the load forecast.

5.3 Overview of Forecast Methodology

I&M's load forecasts are based mostly on econometric, statistically adjusted end-use and analyses of time-series data. This is helpful when analyzing future scenarios and developing confidence bands in addition to objective model verification by using standard statistical criteria.

I&M utilizes two sets of econometric models: 1) a set of monthly short-term models which extends for approximately 24 months and 2) a set of monthly long-term models which extends for approximately 30 years. The forecast methodology leverages the relative analytical strengths of both the short- and long-term methods to produce a reasonable and reliable forecast that is used for various planning purposes.

For the first full year of the forecast, the forecast values are generally governed by the short-term models. The short-term models are regression models with time series errors which analyze the latest sales and weather data to better capture the monthly variation in energy sales for short-term applications like capital budgeting and resource allocation. While these models produce extremely accurate forecasts in the short run, without logical ties to economic factors, they are less capable of capturing structural trends in electricity consumption that are more important for longer-term resource planning applications.

The long-term models are econometric, and statistically adjusted end-use models which are specifically equipped to account for structural changes in the economy as well as changes in customer consumption due to increased energy efficiency. The long-term forecast models incorporate regional economic forecast data for income, employment, households, output, and population.

The short-term and long-term forecasts are then blended to ensure a smooth transition from the short-term to the long-term forecast horizon for each major revenue class. There are some instances when the short-term and long-term forecasts diverge, especially when the long-term models are incorporating a structural shift in the underlying economy that is expected to occur within the first 24 months of the forecast horizon. In these instances, professional judgment is used to ensure that the final forecast that will be used in the peak models is reasonable. The class level sales are then summed and adjusted for losses to produce monthly net internal energy sales for the system. The demand forecast model utilizes a series of algorithms to allocate the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

A flow chart depicting the sequence of models used in projecting I&M's electric load requirements as well as the major inputs and assumptions that are used in the development of the load forecast is shown in Figure 10.

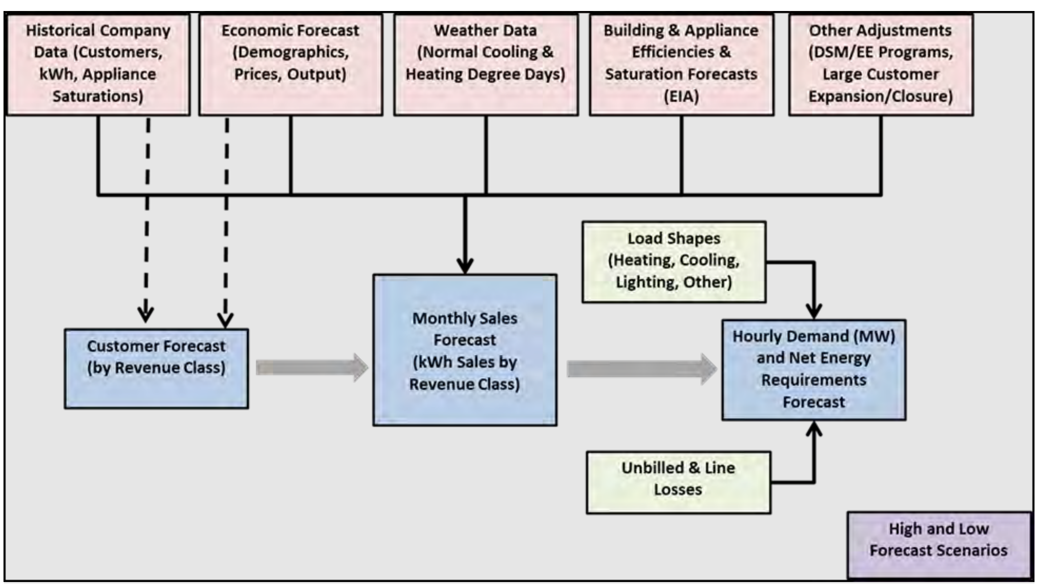


Figure 10. I&M Internal Energy Requirements and

Peak Demand Forecasting Method

5.4 Detailed Explanation of Load Forecast

5.4.1 General

This section provides a more detailed description of the short-term and long-term models employed in producing the forecasts of I&M's energy consumption, by customer class. Conceptually, the difference between short- and long-term energy consumption relates to changes in the stock of electricity-using equipment and economic influences, rather than the passage of time. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology influence the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include all or most of them in the formulation of long-term energy forecasts.

5.4.2 Relative Energy Prices Impact on Electricity Consumption.

One important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to affect them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

5.4.3 Customer Forecast Models

The Company also utilizes both short-term and long-term models to develop the final customer count forecast. The short-term customer forecast models are time series models with intervention (when needed) using Autoregressive Integrated Moving Average (ARIMA) methods of estimation. These models typically extend for 24 months into the forecast horizon.

The long-term residential customer forecasting models are also monthly but extend for over 30 years. The explanatory jurisdictional economic and demographic variables may include gross regional product, employment, population, real personal income and households used in various combinations. In addition to the economic explanatory variables, the long-term customer models employ a lagged dependent variable to capture the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The short-term and long-term customer forecasts are blended as was described earlier to arrive at the final customer forecast that will be used as a primary input into both short-term and long-term usage forecast models.

5.4.4 Short-term Forecasting Models

The goal of I&M's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area. The forecasts relied on ARIMA models.

The estimation period for the short-term models was January 2011 through January 2021. There are models for residential, commercial, industrial, other retail, and wholesale sectors. The industrial models are comprised of 20 (10 in each jurisdiction) large industrial models and models for the remainder of the industrial sector. The wholesale forecast is developed using models for Auburn, Indiana Municipal Power Association, Wabash Valley Power Association, and Dowagiac.

Off-system sales and/or sales of opportunity are not relevant to the net energy requirements forecast as they are not requirements load or relevant to determining capacity and energy requirements in the IRP process.

5.4.5 Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to and beyond 30 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the I&M service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model.

Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1995-2020, with some variation in the estimation period for the various models. The long-term energy sales forecast is developed by blending of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

5.4.6 Supporting Model

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including natural gas price models for I&M's Indiana and Michigan service areas. These models are discussed below.

5.4.6.1 Consumed Natural Gas Pricing Model

The forecast price of natural gas used in the Company's energy models comes from a model of natural gas prices for three primary consuming sectors: residential, commercial, and industrial. In the natural gas price models, sectoral prices are related to East North Central Census region's sectorial prices, with the forecast being obtained from EIA's "2021 Annual Energy Outlook." The natural gas price model is based upon 1980-2020 historical data.

5.4.6.2 Residential Energy Sales

Residential energy sales for I&M are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

The residential usage model is estimated using a Statistically Adjusted End-Use model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool, and other. The SAE model constructs variables to be used in an econometric equation where residential usage is a function of Xheat, Xcool, and Xother variables.

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, cooling degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from I&M's residential customer survey. The saturation forecasts are based on EIA forecasts and analysis by Itron. The efficiency trends are based on DOE forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE residential model is estimated using linear regression models. These monthly models are typically for the period January 1998 through January 2021, with some variation on the estimation period for the individual models. It is important to note, as will be discussed later, that this modeling *has* incorporated the reductive effects of the EPAct, EISA, American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA2008) on the residential (and commercial) energy usage based on analysis by the EIA regarding appliance efficiency trends.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

Separate residential SAE models are estimated for the Company's Indiana and Michigan jurisdictions.

5.4.6.3 Commercial Energy Sales

Long-term commercial energy sales are forecast using SAE models. These models are similar to the residential SAE models. These models utilize efficiencies, square footage and equipment saturations for the East North Central Region, along with electric prices, economic drivers from Moody's Analytics, heating and cooling degree-days, and billing cycle days. As with the residential models, there are Xheat, Xcool and Xother variables derived within the model framework. The commercial SAE models are estimated similarly to the residential SAE models.

5.4.6.4 Industrial Energy Sales

The Company uses some combination of the following economic and pricing explanatory variables: service area gross regional product manufacturing, service area manufacturing employment, FRB industrial production indexes, and service area industrial electricity prices. In addition, binary variables for months and special occurrences are incorporated into the models. Based on information from customer service engineers, there may be load added or subtracted from the model results to reflect plant openings, closures or load adjustments. Separate models are estimated for the Company's Indiana and Michigan jurisdictions. The last actual data point for the industrial energy sales models is January 2021.

5.4.6.5 All Other Energy Sales

The forecast of public-street and highway lighting relates energy sales to either service area employment or service area population and binary variables.

Wholesale energy sales are modeled relating energy sales to economic variables such as service area gross regional product, industrial production indexes, energy prices, heating and cooling degree-days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition or deletion of new customers.

5.4.7 Internal Energy Forecast

5.4.7.1 Blending Short and Long-Term Sales

Forecast values for 2021 and 2022 are taken from the short-term process. Forecast values for 2021 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July 2023 the entire forecast is from the long-term models. The goal of the blending process is to leverage the relative strengths of the short-term and long-term models to produce the most reliable forecast possible. However, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon.

5.4.7.2 Large Customer Changes

The Company's customer service engineers frequently are in touch with large commercial and industrial customers about their needs for electric service. These customers relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then add factors may be used to reflect those large changes that are different from the forecast models' output.

5.4.7.3 Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all Federal Energy Regulatory Commission (FERC) revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are applied to the final blended sales forecast by revenue class and summed to arrive at the final internal energy requirements forecast.

5.4.8 Forecast Methodology for Seasonal Peak Internal Demand

The demand forecast model is a series of algorithms for allocating the monthly internal energy sales forecast to hourly demands. The inputs into forecasting hourly demand are blended revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly Company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges.

In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of I&M and the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-East, AEP-West, or total AEP System. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season, or year).

5.5 Load Forecast Results and Issues

All tables referenced in this section can be found in the Appendix of this Report in Exhibit A. The load forecast includes the forecast impact of customers opting for alternative generation suppliers. This is consistent with the Company's requirement to include such customers' load in its capacity planning in PJM.

5.5.1 Load Forecast

Exhibit A-1 presents I&M's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial, other internal sales and losses) on an actual basis for the years 20011-2020, 2021 data are six months actual, and six months forecast and on a forecast basis for the years 2022-2041. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Company's Indiana and Michigan service areas are given in Exhibits A-2A and A-2B. Figure 11 provides a graphical depiction of weather normal and forecast Company residential, commercial, and industrial sales for 2002 through 2041.

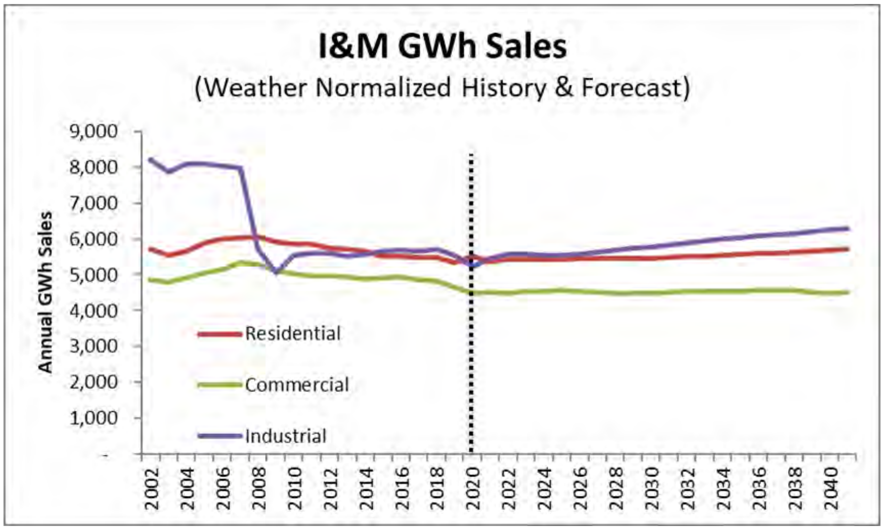


Figure 11. I&M GWh Retail Sales

5.5.2 Peak Demand and Load Factor

Exhibit A-3 provides I&M's seasonal peak demands, annual peak demand, internal energy requirements and annual load factor on an actual basis for the years 2011-2020, 2021 data are six months actual, and six months forecast and on a forecast basis for the year 2022-2041. The table also shows annual growth rates for both the historical and forecast periods.

Figure 11 presents actual, weather normal and forecast I&M peak demand for the period 2000 through 2041. Figure 12depicts the Company's annual peak demand, which occurs in the summer season.

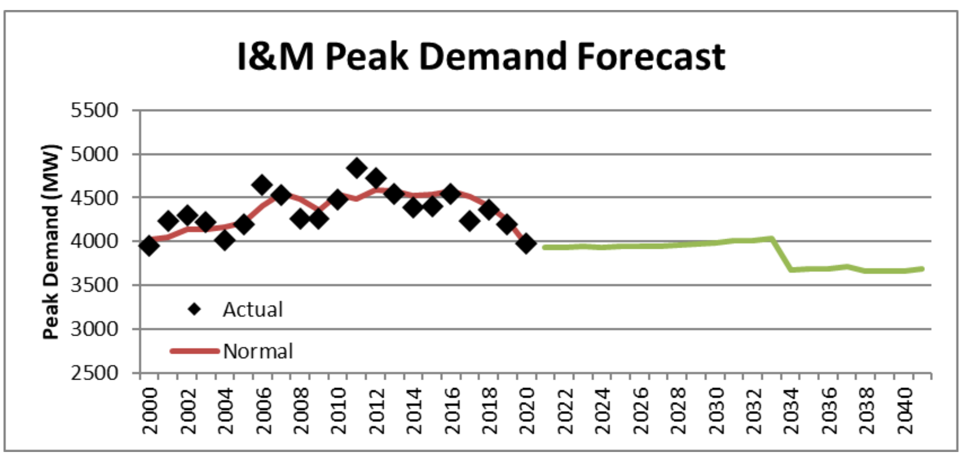


Figure 12. I&M Peak Demand Forecast

5.5.3 Performance of Past Forecasts

The performance of the Company's past load forecasts is reflected in Exhibit A-5, which displays, in graphical form, annual internal energy requirements and summer peak demands experienced since

2000, along with the corresponding forecasts made in 2007, 2009, 2011, 2013, 2015, 2019 and 2021 (the current forecast). This exhibit reflects the uncertainty inherent in the forecasting process and demonstrates the changing perceptions of the future.

5.5.4 Historical and Projected Load Profiles

Exhibits A-6 through A-9 display various historical and forecasted load profiles pertinent to the planning process. Exhibit A-6 shows profiles of monthly peak internal demands for I&M on an actual basis for the years 2005, 2015 and 2020, and as forecasted for 2030 and 2040. Exhibit A-7 shows, for the winter-peak month and summer-peak month for the years 2015 and 2020, respectively, I&M's average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit A-8 displays, for the forecast years 2022 and 2032, I&M's daily internal load shapes for a simulated week in the winter-peak month (January) and summer-peak month (August). In both cases, a weekday is assumed to represent the day of the monthly (and seasonal) peak. Such load shapes were developed for use in integrated resource planning analyses.

The Company maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit A-9 displays I&M's Indiana jurisdiction residential, commercial, and industrial customer class summer and winter 2020 load shape information derived from these samples.

5.5.5 Weather Normalization

The load forecast presented in this report assumes normal weather. To the extent that weather is included as an explanatory variable in various short- and long-term models, the weather drivers are assumed to be normal for the forecast period.

Exhibit A-10 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for I&M for the last ten years, 2011-2020.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. So, a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time that ultimately produces a weather normalized peak.

Similarly, for each year, the weather-normalized internal energy requirements were determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each sector of the recorded internal energy requirements. The adjustment for each sector was obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which was estimated by regressing over the past years monthly sectoral energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each sector were then added for all sectors across all twelve months to obtain the net total weather-normalized energy requirements for the year.

5.5.6 Data Sources

The data used in developing the I&M load forecast come from both internal and external sources. The external sources are varied and include state and federal agencies, as well as Moody's Analytics. Exhibit A-11 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecast.

5.6 Load Forecast Trends & Issues

5.6.1 Changing Usage Patterns

Over the past decade, there has been a significant change in the trend for electricity usage from prior decades. Figure 13 presents I&M's historical and forecasted residential and commercial usage per customer between 1991 and 2030. During the first decade shown (1991-2000), residential usage per customer grew at an average rate of 0.5% per year, while the commercial usage also grew by 0.5% per year. Over the next decade (2001-2010), growth in residential usage growth was at 0.5% per year while the commercial class usage decreased by 0.6% per year. In the next decade shown (2011-2020) residential usage declined at a rate of 1.0% per year while the commercial usage decreases by an average of 1.6% per year. The COVID-19 Pandemic had a significant impact on residential and commercial usage. With more people at home, residential usage increased by 1.6% in 2020. Meanwhile, with the economy shutdown, commercial usage declined by 5.2% in 2020. Efficiency gains are expected to continue over the next ten year (2021-2030), residential is projected to decline slightly and commercial is forecast to decline by 0.3% per year.

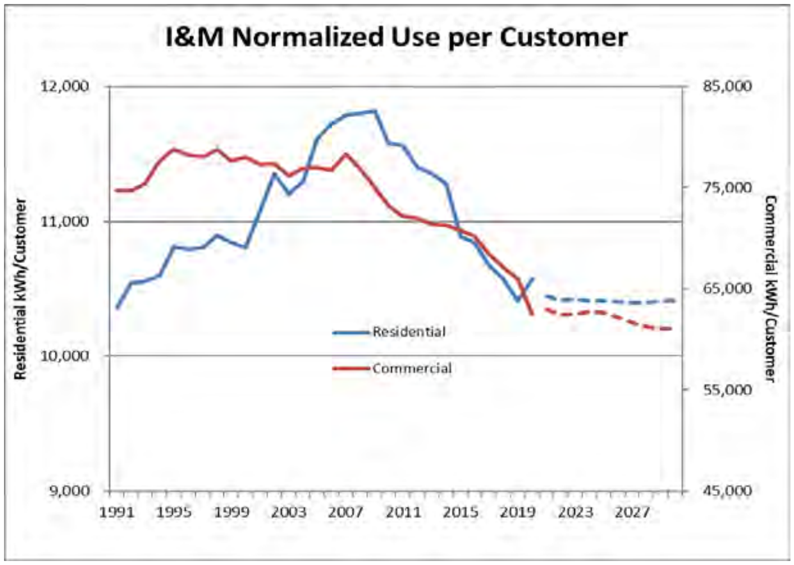


Figure 13. I&M Normalized Use per Customer (kWh)

The SAE models are designed to account for changes in the saturations and efficiencies of the various end-use appliances. Every 3-4 years, the Company conducts a Residential Appliance Saturation Survey to monitor the saturation and age of the various appliances in the residential home. This information is then matched up with the saturation and efficiency projections from the EIA which includes the projected impacts from various enacted federal policies mentioned earlier.

The result of this is a base load forecast that already includes some significant reductions in usage as a result of projected EE. For example, Figure 14 shows the assumed cooling efficiencies embedded in the statistically adjusted end-use models for cooling loads. It shows that the average Seasonal Energy Efficiency Ratio (SEER) for central air conditioning is projected to increase from 11.9 in 2010 to nearly 14.8 by 2040. The chart shows a similar trend in projected cooling efficiencies for heat pump cooling as well as room air conditioning units. Figure 15 shows similar improvements in the efficiencies of lighting and refrigerators over the same period. There are not much additional efficiency gains expected from lighting for residential customers, as consumers have adopted the newer technologies and moved away from incandescent lighting.

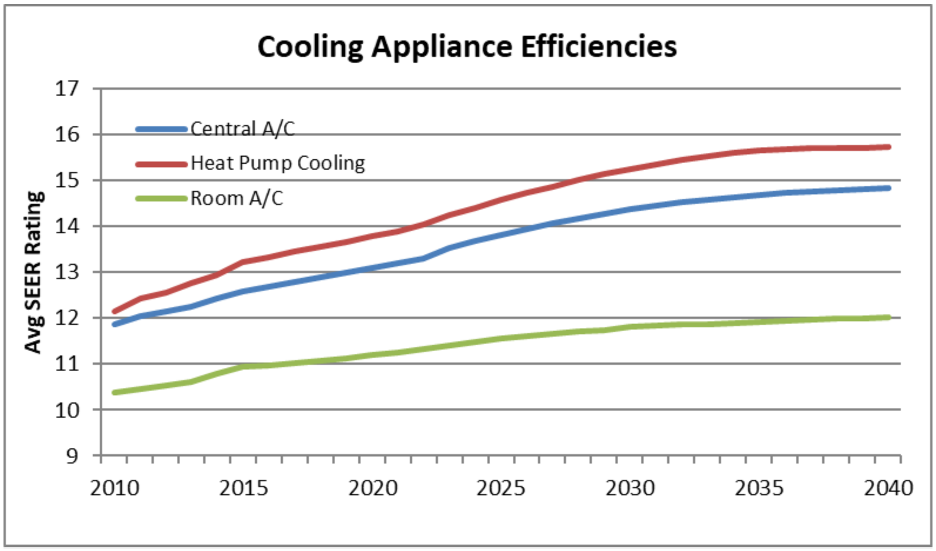


Figure 14. Projected Changes in Cooling Efficiencies, 2010-2040

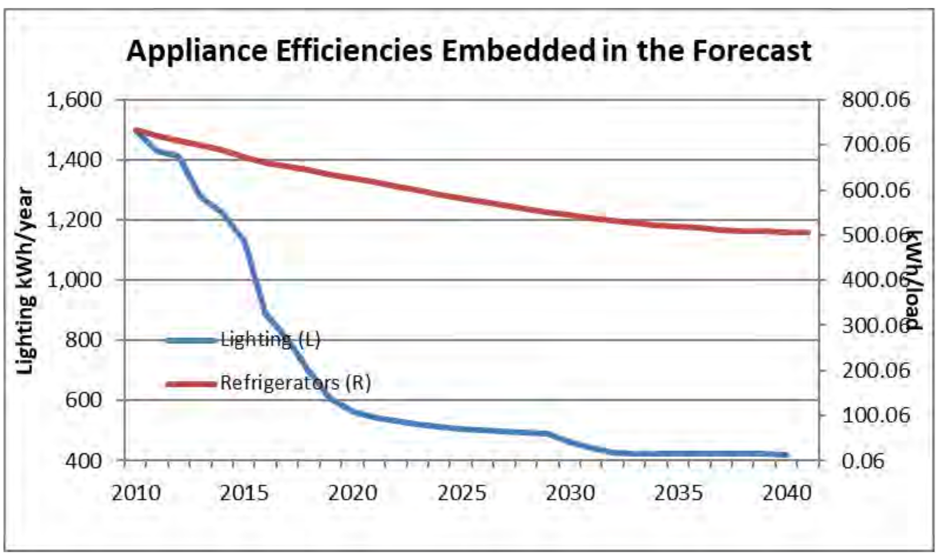


Figure 15. Projected Changes in Lighting & Clothes Washer Efficiencies, 2010-2040

Figure 16 shows the impact of appliance, equipment, and lighting efficiencies on the Company's weather normal residential usage per customer. This graph provides weather normalized residential energy per customer and an estimate of the effects of efficiencies on usage. In addition, historical and forecast I&M residential customers are provided.

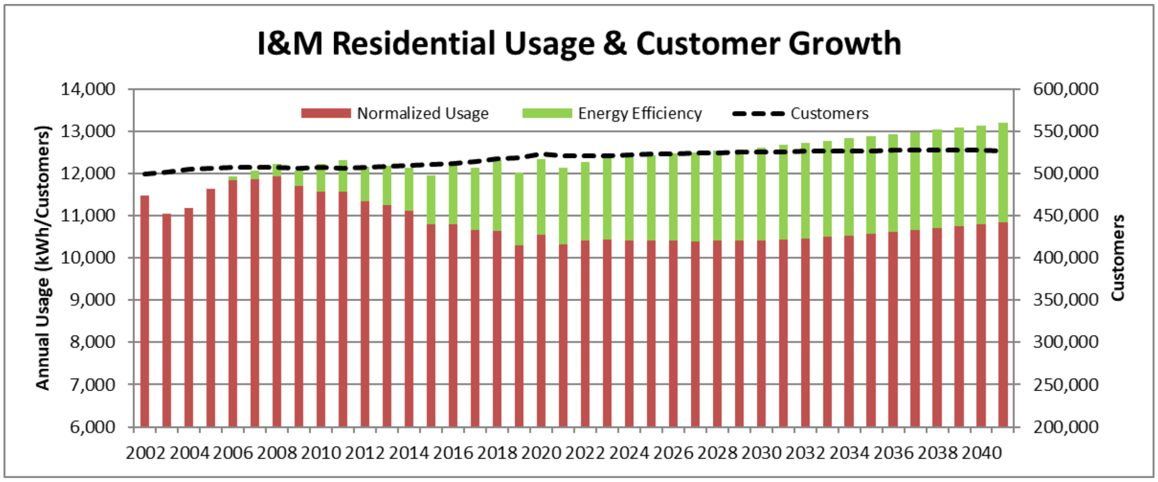


Figure 16. Residential Usage & Customer Growth

5.6.2 Demand-Side Management (DSM) Impacts on the Load Forecast

The end-use load forecasting models account for changing trends and saturations of energy efficient technologies throughout the forecast horizon. In addition, the Company is also actively engaged in implementing various commission approved DSM and EE programs which would further accelerate the adoption of energy efficient technology within its service territory. Itron's SAE model relies on the EIA) Annual Energy Outlook (AEO) to account for future appliance efficiencies. EIA AEO documentation[8] specifically states its forecast data (used by Itron in the SAE) "accounts for the effects of utility-level energy efficiency programs designed to stimulate investment in more efficient equipment for space heating, air conditioning, lighting, and other select appliances". As a result, the Company applies a Supplemental Efficiency Adjustment (SEA) to prevent double counting the impacts from the Company-sponsored energy efficiency programs in the load forecast.

For the near-term horizon (through 2022), the load forecast applies energy and demand savings impact assumptions from the current DSM programs. For the years beyond 2022, the IRP model selected optimal levels of incremental economic EE, which may differ from the levels currently being implemented, based on projections of future market conditions, the future expected costs of available supply resources, and the level of available incremental EE. Since the initial base load forecast accounts for the evolution of market and industry efficiency standards, the energy savings for each specific EE program are adjusted over the expected life of the program. Exhibit A-17 details the impacts of the approved EE programs included in the load forecast, which represent the cumulative adjusted value of EE program impacts throughout the forecast period that were applied to the load forecast. While the IRP optimization process selects the optimal incremental economic EE, the

8 Assumptions to the Annual Energy Outlook 2021: Residential Demand Module, section labeled Energy Efficiency Rebates on pg. 6 of 12 https://www.eia.gov/outlooks/aeo/assumptions/pdf/residential.pdf

resulting total annual IRP EE program savings contains both the ongoing impacts from current programs and the optimized levels of EE from the IRP process.

Exhibit A-12 provides the DSM/EE impacts incorporated in I&M's load forecast provided in this Report. Annual energy and seasonal peak demand impacts are provided for the Company and its Indiana and Michigan jurisdictions.

5.6.3 Interruptible Load

The Company has two customers with interruptible provisions in their contracts. These customers have a combined interruptible contract capacity of 15MW. However, these customers are expected to have only 14MW available for interruption for winter and summer peaks. An additional 135 customers have 248MW available for interruption in emergency situations in DR agreements. The load forecast does not reflect any load reductions for these customers. Rather, the interruptible load is seen as a resource when the Company's load is peaking. As such, estimates for DR resource impacts are reflected by I&M in determination of PJM-required resource adequacy (i.e., I&M's projected capacity position).

5.6.4 Blended Load Forecast

As noted above, at times the short-term models may not capture structural changes in the economy as well as the long-term models, which may result in the long-term forecast being used for the entire forecast horizon. Exhibit A-13 provides an indication of which retail models are blended and which strictly use the long-term model results. In addition, all of the wholesale forecasts utilize the long-term model results.

In general, forecast values for the years 2021 and 2022 were typically taken from the short-term process. Forecast values for 2023 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by July of 2023 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results. Figure 17 illustrates a hypothetical example of the blending process (details of this illustration are shown in Exhibit A-14). However, in the final review of the blended forecast, there may be instances where the short-term and long-term forecasts diverge especially when the long-term forecast incorporates a structural shift in the economy that is not included in the short-term models. In these instances, professional judgment is used to develop the most reasonable forecast.

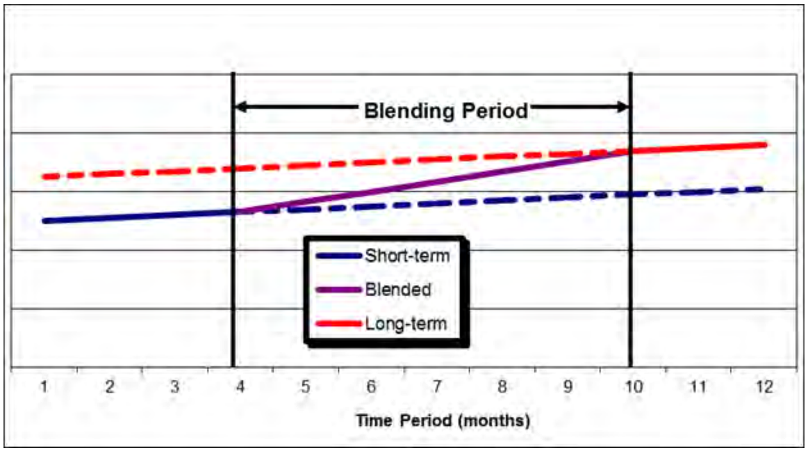


Figure 17. Load Forecast Blending Illustration

5.6.5 Large Customer Changes

The Company's customer service engineers are in continual contact with the Company's large commercial and industrial customers about their needs for electric service. These customers will relay information about load additions and reductions. This information will be compared with the load forecast to determine if the industrial or commercial models are adequately reflecting these changes. If the changes are different from the model results, then additional factors may be used to reflect those large changes that differ from the forecast models' output.

5.6.6 Wholesale Customer Contracts

Company representatives are in continual contact with wholesale customer representatives about their contractual needs. The forecast included in this IRP does not assume the automatic renewal of expiring wholesale contracts. This assumption results in significant load drops in the 2030s.

5.7 Load Forecast Model Documentation

Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendices Volume 1-Exhibit F, Volume 2, and Volume 3-Exhibits C, D and E.

5.8 Changes in Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M and AEP on a continuing basis. The forecasts reported herein do not reflect any significant methodological changes since the last IRP filing.

5.9 Load-Related Customer Surveys

A residential customer survey was last conducted in the fall of 2018 in which data on end-use appliance penetration and end-use saturation rates were obtained. Beginning in 1980, in intervals of approximately three years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts.

The Company has not conducted its own industrial and/or commercial customer end-use surveys because of the significant cost considerations involved. The Company relies on the EIA for this information which is collected in their Commercial Buildings Energy Consumption Survey (CBECS) and Manufacturing Energy Consumption Survey (MECS). I&M also monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

5.10 Load Research Class Interval Usage Estimation Methodology

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee, was a significant contributor to the AEIC Load Research Manual, and uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from actually metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1MW, a statistical random sample is designed and selected to provide at least 10% precision at the 90% confidence level at times of company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using Model Based Statistical Sampling. Model Based Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an Advanced Metering Infrastructure (AMI) area, the interval data is extracted from the Meter Data Management System (MDM) and stored in Hadoop or imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in 15- minute intervals. For rate classes in which customer maximum demand is normally 1MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System or the MDM, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through the Load Research Analysis System. The sample interval data is post-stratified and weighted to represent the sampled class populations, and total class hourly load estimates are developed. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

5.11 Customer Self-Generation

I&M customers that install renewable energy resource self-generation facilities are typically served through either I&M's Net Metering Service Rider (Rider NMS) or Cogeneration and/or Small Production Service (Tariff COGEN/SPP).

Through November 2020, 818 customers have installed net metering and or co-generation qualifying customer-generation facilities which are interconnected and/or net metered with a total nameplate capacity of approximately 17.966 MW.

In comparison to I&M's total system load, current levels customer self-generation (net metering and co-generation) are not overly impactful.

Since the prior IRP, the number of connected qualifying customer-generation facilities in the I&M service territory has grown by 174%, yet the total nameplate capacity has only grown by 138%. This indicates more customers are installing self-generation over the past few years, but the average nameplate size of systems is decreasing.

The Company's load forecast considers these historical trends and assumes a continuation of this trend in customer self-generation load.

In 2020, the Company undertook a market potential study (MPS) that assessed, in part, the future potential for Distributed Energy Resources to be connected to I&M's energy delivery system. This review was performed by an MPS industry consultant and culminated in a forecast for customer-owned solar and Combined Heat and Power (CHP). For both resource types, the MPS found customer ownership and operation of these systems not economic at current cost levels seen in these industries.

This IRP uses the MPS potential for customer-owned generation as DER since this potential above the historical trend is not included as part of the load forecast.

5.12 Load Forecast Scenarios

The base case load forecast is the expected path for load growth that the Company uses for planning. There are a number of known and unknown potentials that could drive load growth different from the base case. While potential scenarios could be quantified at varying levels of assumptions and preciseness, the Company has chosen to frame the possible outcomes around the base case. The Company recognizes the potential desire for a more exact quantification of outcomes, but the reality is if all possible outcomes were known with a degree of certainty, then they would become part of the base case.

Forecast sensitivity scenarios have been established which are tied to respective high and low economic growth cases. The high and low economic growth scenarios are consistent with scenarios laid out in the EIA's 2021 Annual Outlook. While other factors may affect load growth, this analysis only considered high and low economic growth. The economy is seen as a crucial factor affecting future load growth.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for I&M are tabulated in Exhibit A-15.

For I&M, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2041, represent deviations of about 14.0% below and 17.1% above, respectively, the base-case forecast.

During the load forecasting process, the Company developed various other scenarios. Figure 18 provides a graphical depiction of the scenarios developed in conjunction with the load provided in this report.

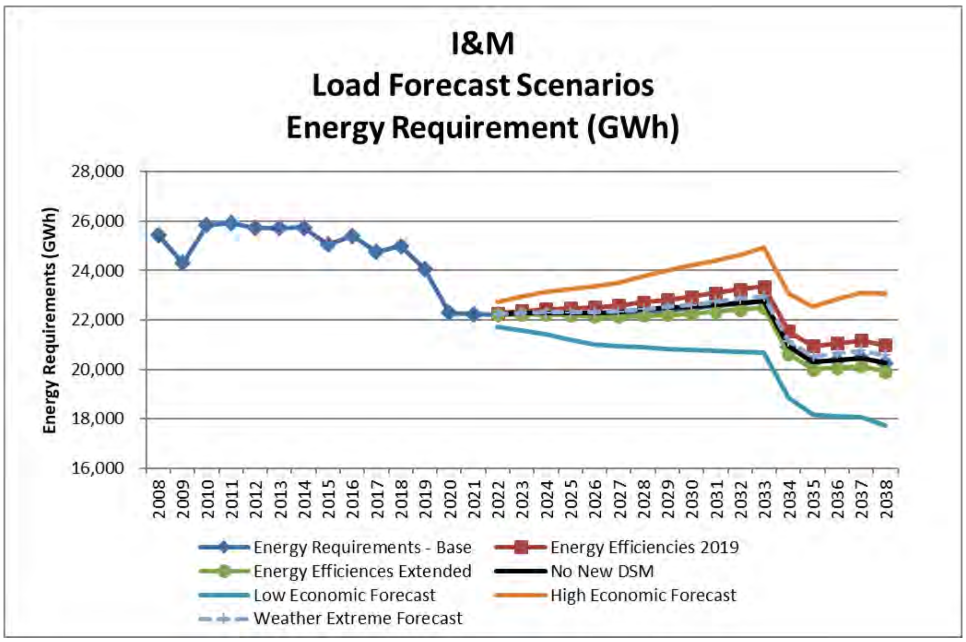


Figure 18. Load Forecast Scenarios

The no new DSM scenario extracts the DSM included in the load forecast and provides what load would be without the increased DSM activity. The energy efficiencies 2021 scenario keeps energy efficiencies at 2021 levels for the residential and commercial equipment. Both of these scenarios result in a load forecast greater than the base forecast.

The energy efficiencies extended scenario has energy efficiencies developing at a faster pace than is represented in the base forecast. This scenario is based on analysis developed by the Energy Information Administration. This forecast is lower than the base forecast due to enhanced energy efficiency for residential and commercial equipment.

The weather extreme forecast assumes increased average daily temperatures for both the winter and summer seasons which results in diminished heating degree-days in the winter and increased cooling degree days in the summer. This analysis is based on a potential impact of climate change developed by Purdue University. The extreme weather scenario was developed in response to inquiries in one of the Company's Stakeholder meetings. This scenario results in increased load in the summer and diminished load in the winter, with the net result being higher energy requirements forecast. Exhibit A-16 provides graphical displays of the range of forecasts of summer and winter peak demand for I&M along with the impacts of the weather scenario for each season.

All of these alternative scenarios fall within the boundary of the Company's high and low economic scenario forecasts. The Company's expectations are that any reasonable scenario developed will fall within this range of forecasts.

Although the Company does not explicitly adjust the load forecast for increased adoption of electric vehicles, it does continually monitor the adoption rate and will address the issue as it becomes more significant. The Company has developed high, low and base scenarios on adoption in the service area through 2030. These scenarios are presented graphically in Figure 19.

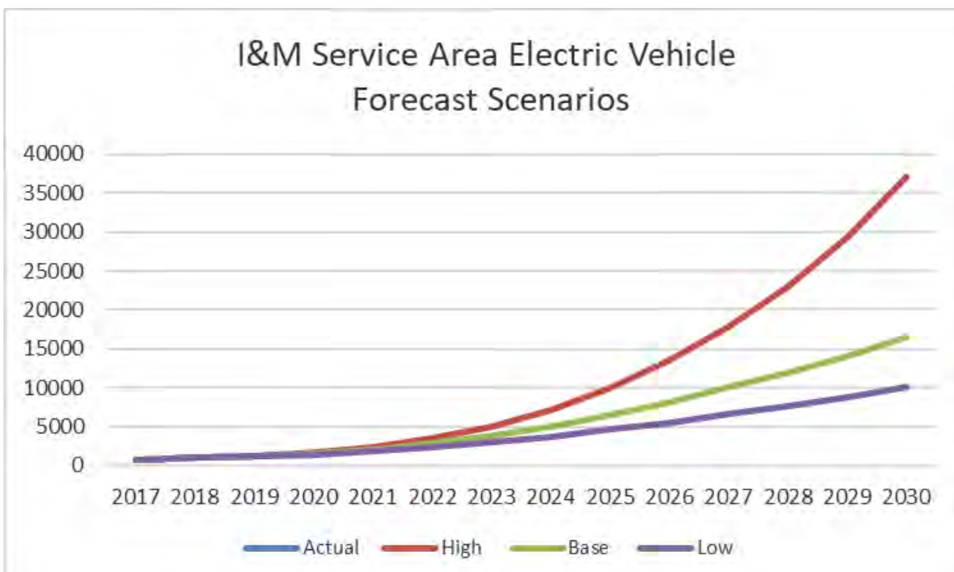


Figure 19. Electric Vehicle Scenarios

The EV scenarios were initially developed in 2018 using a consensus approach from various external sources. These sources included Bloomberg New Energy Finance (BNEF), British Petroleum (BP), ExxonMobil, Organization of Petroleum Exporting Countries (OPEC), International Energy Agency (IEA), and the US Energy Information Administration (EIA). While most of these sources provided macro level forecasts for global or US EV adoption, I&M evaluated the projected growth rates in EV adoption from the various sources to develop its base, high, and low growth scenarios.

To calibrate the EV forecast for the I&M service territory, the Company applied the projected growth rates to the actual EV registration data for the I&M service territory. As of the third quarter of 2021, there are just over 3,800 electric vehicles registered in I&M's Indiana and Michigan service territories.

5.13 Other Considerations Based on Prior Feedback

5.13.1.1 High-Low Economic Scenarios

The Director's Report asked for additional narrative to the high-low economic scenarios. The Company develops a model of aggregate load for Company to evaluate the sensitivity to the spread of the EIA forecast of GDP. Regional economic variables are used in the aggregate model and the spread for these drivers are determined by high-low economic growth provided in EIA's 2021 Energy Outlook. The purpose of the aggregate model to develop a reasonable spread that are applied to the forecast of energy requirements and seasonal peak demand. The high-low scenarios have a larger range than the 2018 IRP, which reflects an increased uncertainty.

Changes in Forecast Methodology

Feedback was provided about the changes load forecast methodology. While the Company did not have any significant changes in load forecast methodology since the last IRP, the Company has explored and plans to implement changes in future IRPs to the residential and commercial sales model to have DSM as an explanatory variable to incorporate DSM effects in the load forecast.

Forecast Blending

Comments were noted about the blending process and the Company often using the long-term forecast. The blending process is an integral part of the Company's forecast process. It entails not only evaluating the annual load growth, but also the monthly variation within each year's forecast. The Company's forecast process evaluates the pros and cons of both the short- and long-term forecasts before determining what they believe is the optimal forecast for the Company for each sector. While the Company has selected the long-term forecast in most instances, the forecast was enriched with the evaluation process and the consideration of the short-term forecast. Furthermore, the Company finds particular value in this process for evaluating monthly forecasts and enhancing monthly forecasting accuracy.

Electric Vehicles

The Director's Report inquired about electric vehicles and the ramifications on system load and load shapes. As discussed in earlier, the Company has been monitoring the adoption of electric vehicles in its service area. While the Company has not explicitly included enhance adoption electric vehicles in the load forecast, it has included its latest forecast of electric vehicles and high-low scenario in the scenario section above.

Customer Surveys.

The Director's Report inquired about customer surveys. The Company continues to do residential surveys every three years or so. The Company has conducted a survey in the fall of 2021. The results from these surveys are being evaluated and are used to enhance the Company's residential energy forecasts. The Company currently does not have plans to do surveys of commercial and industrial customers. These customers are more heterogeneous than the residential sector, which makes it more challenging to conduct a survey that is representative of the Commercial and Industrial class customers in the I&M service territory. The Company believes that the costs of these surveys would outweigh the benefits derived from them so it relies on EIA surveys for the Commercial and Industrial classes at a census region level.

Advanced Metering Infrastructure (AMI)

The Director's Report also discussed the importance of AMI to enhancing the load forecast. The Company initiated a full deployment of AMI in 2021 by completing the AMI network infrastructure and beginning AMI meter deployments. As of the end of 2021, I&M has installed approximately 97,000 AMI meters across its service area, including approximately 67,000 in Indiana and approximately 30,000 in Michigan. The Company plans to install approximately 240,000 AMI meters in Indiana and 104,000 in Michigan in 2022. The full deployment of AMI meters across all of I&M's service area is expected to be complete by 2024.

As the Company gets access to interval data provided by the AMI technology, it will become an integral part of the load forecasting process, as well as our continued efforts to better integrate the planning of generation, transmission and distribution resources and investments. This information will enhance the Company's understanding of customer usage patterns, especially regarding emerging technologies (e.g. electric vehicles, distributed energy resources, etc.), and be a key input to the load forecast. It also will allow the Company to improve its evaluation of the impacts of DSM/EE on hourly loads. Based on the current deployment schedule, the Company would expect to be able to use this data to inform the load forecast that will be used in I&M's next IRP cycle.

Load Shapes

The Company currently relies on its load research data for hourly load shapes by customer class. These load shapes are updated each year and allows the Company to keep track of changes in usage patterns by class. Implementation across the Company of AMI will enhance the Company's understanding of load shapes at the class and sub-class level. The Company currently identifies customers by North American Industrial Classification System (NAICS). Full implementation of AMI would allow the Company to analyze load shapes at a more granular NAICS code level, as needed. AMI will also allow for the Company to develop load shapes for other things such electric vehicles and DSM/EE impacts.

6 Resource Evaluation

6.1 Current Resources

An important step of the IRP process is the demonstration of the capacity resource requirements. This aspect of the traditional "needs" assessment must consider projections of:

- existing capacity resources—current levels and anticipated changes
- anticipated changes in capability due to efficiency and/or environmental considerations
- changes resulting from decisions surrounding unit disposition evaluations
- regional and sub-regional capacity and transmission constraints/limitations
- load and peak demand
- current DR/EE
- PJM capacity reserve margin and reliability criteria

6.2 All-Source Informational RFP

An All-Source Informational RFP was issued at the onset of the IRP process to obtain market information to near term indicative pricing for a wide range of technologies.

I&M issued an All-Source Informational RFP seeking power supply and demand-side proposals for capacity and energy to meet the needs of its customers. The purpose of the RFP was to identify viable resources available to I&M in the marketplace to meet the needs of its customers. I&M used aggregated data from the RFP responses to inform the IRP process.

I&M requested information from the marketplace for the following types of products:

- Commercial structure: Purchase Power Agreement (PPA) or Build-Own-Transfer
- Project development status: New or existing
- Resource type:
    - Dispatchable including Stand-alone Battery Energy Storage System (BESS),
    - Utility scale renewable resources, either stand-alone or paired with storage to support PJM Planning Years beginning 2025/26
    - Load Modifying Resources
    - Demand Response
    - Distributed Generation
    - Qualifying Facility (QF)

In connection with this All-Source Informational RFP, I&M retained the services of an independent third-party consultant, Siemens PTI, to manage the entire RFP process and work with I&M to perform the quantitative and qualitative evaluation of all proposals.

All respondents were directed to interface with Siemens PTI for all communications including questions, RFP clarifications issues, and RFP proposal submittal until late in the evaluation process.

Proposals were initially reviewed for completeness by Siemens PTI. Respondents were contacted for additional data or clarifications by Siemens PTI via designated Siemens PTI email address, imallsourcerfp.us@siemens.com. Each complete proposal was evaluated based on the energy settlement location, interconnection/development status, proposed price, and project risk factors.

6.3 Renewables RFP

In addition to the All-Source Informational RFP conducted as part of this IRP, the Company also issued an RFP in November 2020 requesting proposals for Solar and Wind resources which were due in January 2021. Responses from this RFP effort were combined with the responses from the All-Source Informational RFP to inform the IRP renewable costs.

6.4 Existing Generating Resources and PJM Capacity Planning Requirements

I&M operates in the PJM Interconnection, L.L.C. (PJM) and in ReliabilityFirst Corporation, a Regional Entity of the North American Electric Reliability Corporation (NERC). I&M participates in the PJM energy market. Based on offers placed into this market, the generation resources within the entire PJM RTO are economically dispatched for energy to serve the total PJM load, including I&M's internal load. Separately, PJM has a mandatory capacity market. PJM allows an entity to either participate in a capacity auction (in which PJM functions to procure the capacity) or utilize the Fixed Resource Requirement (FRR) option in which the entity supplies its own capacity resource either through constructing the necessary capacity or through bilateral contracts with existing resources. PJM requires all FRR entities to make mandatory commitments to meet their capacity reserve requirements by supplying PJM with an FRR plan three years in advance of the Planning Year. The same three year forward concept holds for entities using the RPM auction process. The Reliability Assurance Agreement (RAA) sets forth the rules of participation in the PJM Capacity Market and also establishes capacity obligations of PJM Load Serving Entities (LSEs).

Currently, I&M, along with other operating companies of AEP in PJM, collectively participate as a PJM FRR entity and are committed to the FRR option through PJM Planning Year (PY) 2022/23. FRR election decisions and FRR Plans for PJM PY 2023/24 were submitted to PJM November 1, 2021. The underlying minimum reserve margin criterion to be utilized in the determination of I&M's capacity need is based on the PJM Installed Reserve Margin (IRM) of 14.4 percent.[9] The ultimate reserve margin is determined from the PJM Forecast Pool Requirement (FPR), which considers the IRM and PJM's Pool-Wide Average Equivalent Demand Forced Outage Rate (EFORd).[10] The PJM FPR is 8.63% for the 2023/2024 PJM PY, and increases to 8.65% for the remainder of the planning

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9 Per Section 2.1.1 of PJM Manual 18: PJM Capacity Market (Effective: August 1, 2021). PJM Planning Parameters are updated each year prior to the upcoming Base Residual Auction. These values can be obtained from http://pjm.com/markets-and-operations/rpm.aspx. This IRP uses the PJM Planning Parameters, which reflect PJM's Capacity Performance proposal, as currently interpreted by I&M.

10 Per Section 2.1.4 of PJM Manual 18: PJM Capacity Market (Effective: August 1, 2021).
FPR = (1 + IRM) * (1 – EFORD). Reserve Margin = FPR – 1.

period. As discussed earlier, the Company included the Reserve Margin metric in the Balanced Scorecard to ensure the Candidate Portfolios are meeting this requirement.

Table 5 identifies the current generating resources included in the Company's plan. Future plans surrounding these assets must consider each unit's useful service life. Unit retirements are incorporated in I&M's plans based upon each unit's in-service date along with the anticipated service life. Retirement dates are periodically reviewed and adjusted with respect to a unit's ability to maintain safe, reliable, and economic operation, as well as external factors such as environmental regulations.

Table 5. I&M Generation Assets as of December 2020

Unit Name	Location	Fuel Type	C.O.D. [1]	PJM Nameplate Capacity (MW)	PJM Unforced Capacity (MW)	
Cook 1	Bridgman, MI	Nuclear	1975	1,084	986	
Cook 2	Bridgman, MI	Nuclear	1978	1,204	1,125	
Rockport 1	Rockport, IN	Coal	1984	1,122	1,072	(A)
Rockport 2	Rockport, IN	Coal	1989	1,122	1,051	(A)
Berrien Springs 1-12	Berrien Springs, MI	Water	1908	7	3	
Buchanan 1-10	Buchanan, MI	Water	1919	4	1	
Constantine 1-4	Constantine, MI	Water	1921	1	0.2	
Elkhart 1-3	Elkhart, IN	Water	1913	2	2	
Mottville 1-4	White Pigeon, MI	Water	1923	1.7	0.5	
Twin Branch 1-8	Mishawaka, IN	Water	1904	5	3	
Fowler Ridge 1	Benton County, IN	Wind	2008	100	13	(B)
Fowler Ridge 2	Benton County, IN	Wind	2009	50	7	(B)
Headwaters	Randolph County, IN	Wind	2014	200	26	(B)
Wildcat	Madison County, IN	Wind	2014	100	13	(B)
Deer Creek	Grant County, IN	Solar	2015	3	1	
Olive	St. Joseph County, IN	Solar	2016	5	3	
St. Joseph Solar	St. Joseph County, IN	Solar	2021	20	6	
Twin Branch Solar	St. Joseph County, IN	Solar	2016	3	1	
Watervliet	Berrien County, MI	Solar	2016	5	2	
Clifty Creek 1-6	Madison, IN	Coal	1956	102	82	(C)
Kyger Creek 1-5	Cheshire, OH	Coal	1955	85	68	(C)
				5,226	4,464	

(1) Commercial operation date.
(A) Represents I&M's share of these units (85%)
(B) Represents capacity from Power Purchase Agreements (PPAs)
(C) Represents I&M's share of the OVEC capacity under the ICPA

Furthermore, in September 2021, the Company received the necessary approval from FERC to authorize the acquisition of Rockport Unit 2. Additionally, the Company entered into a Settlement Agreement[11] with Stakeholders related to the Operation of Rockport Unit 2. In summary and in part, Rockport Unit 2 will be used as transitional capacity resource for I&M through the 2023/2024 Planning Year, allowing I&M to use up to 650MW for its capacity obligation. Also as part of the Settlement Agreement, beginning with the 2024/2025 PJM Planning Year and through the remainder of its operating life, 100% of Rockport Unit 2 will be treated as a merchant generating unit and participate in the PJM markets as an RPM-only resource.

[11] IURC Cause No. 45546

Figure 20 below depicts I&M's current generation resources, their nameplate ratings and current age.

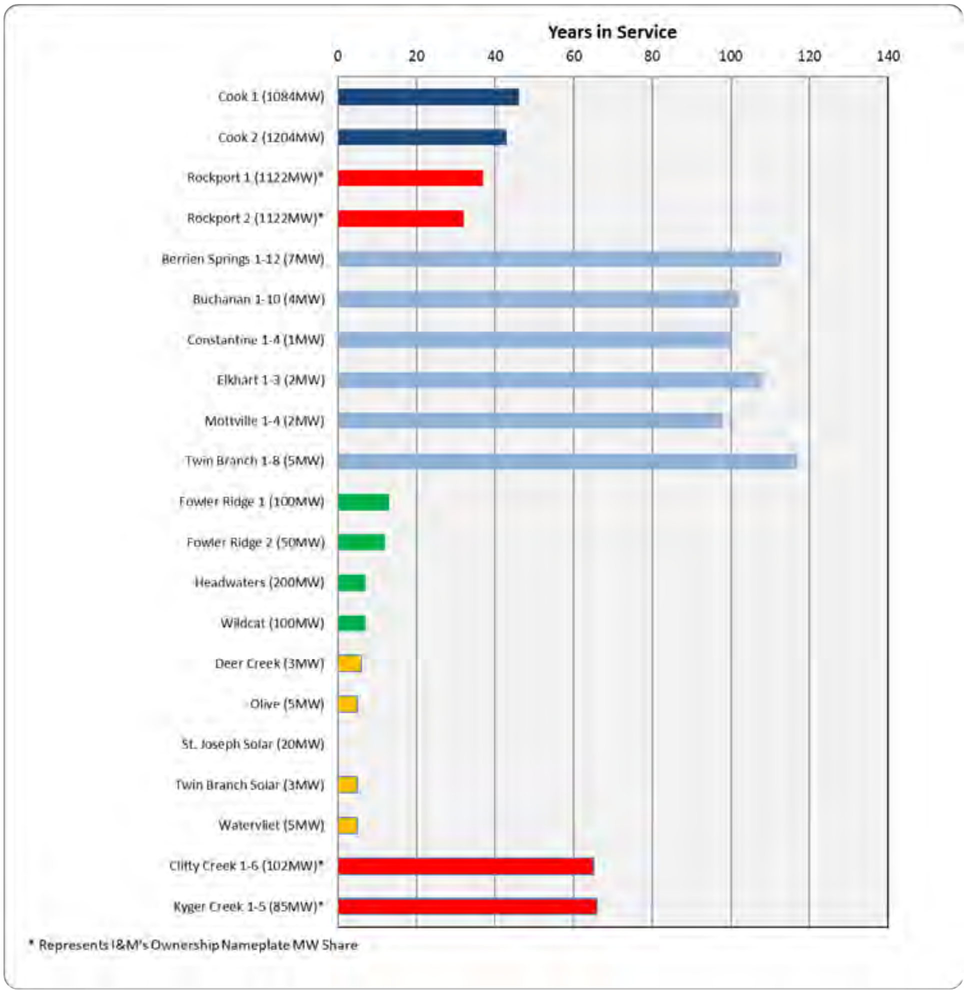

Figure 20. Current Resource Fleet (Owned & Contracted) with years in Service, as of April 1, 2021

I&M currently utilizes several capacity entitlements to meet the minimum PJM reserve margin requirement, including generation from Company owned assets, and power purchase agreements.

6.4.1 PJM Capacity Performance Rule Implications

On June 9, 2015, FERC issued an order largely accepting PJM's proposal to establish a new "Capacity Performance" product. The resulting PJM rule requires future capacity auctions to transition from current or "Base" capacity products to Capacity Performance products. Capacity Performance resources will be held to stricter requirements than current Base resources and will be assessed heavy penalties for failing to deliver energy when called upon. The rulemaking was effective with the 2020/2021 PJM Planning Year.

For this IRP, the Company assumes it will continue as a Fixed Resource Requirement (FRR) entity within the PJM Capacity planning process which I&M has now notified PJM it will do. The Company also assumes, consistent with the Capacity Performance rule, that unit capabilities will be based on the current Unforced Capacity (UCAP) definition, which is Installed Capacity (ICAP) times 1 minus EFORd or ICAP X (1 – EFORd).

6.4.2 Fuel Inventory and Procurement Practices – Coal

I&M plans to have adequate fuel supplies at its coal generating units to meet full-load burn requirements in both the short-term and the long-term. American Electric Power Service Corporation (AEPSC), acting as agent for I&M, is responsible for the procurement and delivery of coal to I&M's coal generating station, as well as establishing coal inventory target level ranges and managing those levels. AEPSC's primary objective is to assure the availability of an adequate, reliable supply of coal at the lowest reasonable delivered cost. Deliveries are arranged so that sufficient coal is available at all times. The consistency and quality of the coal delivered to the generating station is also vitally important. The consistency of the sulfur content of the delivered coal is fundamental to I&M's achievement and compliance with the applicable environmental limitations.

6.4.3 Specific Units

I&M has one coal-fired generating station in Indiana. The Rockport Generating Station, located in Spencer County, consists of two 1,300-megawatt nameplate coal fired generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited to 1.2 lb. SO_2/MMBtu and there is a SO_2 cap on emissions which began in 2016. Compliance with the emission limit is achieved by using a blend consisting primarily of low-sulfur bituminous and sub-bituminous coal. The coal supply for Rockport currently uses a blend of sub-bituminous Powder River Basin (PRB) coal from Wyoming and low-sulfur bituminous coal from Central Appalachian basin and/or Colorado basin sources. In order to comply with stricter EPA emissions standards, Dry Sorbent Injection (DSI) technology is being used at both Rockport units. The DSI technology did not change the coal blend at Rockport.

6.4.4 Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. I&M's total coal requirements are met using a portfolio of long-term arrangements and spot-market purchases that are primarily made through a competitive Request for Proposal process. Long-term contracts (>1 year) support a relatively stable and consistent supply of coal, but often do not provide the required flexibility to meet changes in demand for coal fired generation in a low gas price and/or low power demand scenario. Spot purchases are used to provide additional flexibility to accommodate changing demand. Occasionally, spot purchases may also be made to test-burn any promising and potential new sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

6.4.5 Contract Descriptions

Rockport's PRB coal supply needs for 2021 and 2022 are being supplied primarily through two long-term supply agreement with Peabody COALSALES, LLC. Rockport's Central Appalachian coal supply needs for 2021 is being supplied under one long-term supply agreement with Blackhawk Coal Sales, LLC. As these agreements expire, additional coal supplies will be contracted to maintain a sufficient supply of coal.

6.4.6 Inventory

I&M coordinates to maintain an adequate coal supply to meet full-load burn requirements at the plant. However, in situations where coal supplies fall below prescribed minimum levels, programs have been developed to conserve coal supplies. In the event of a severe coal shortage, I&M would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

6.4.7 Fuel Inventory and Procurement Practices – Uranium

Uranium inventory for nuclear power is different than traditional inventories such as coal. No uranium is stored or brought to the Donald C. Cook (DC Cook) nuclear power plant in the raw material form. Uranium in its raw material form (commonly referred to as Yellowcake of U3O8) undergoes multiple processes before arriving on-site as fully fabricated fuel assemblies.

I&M purchases the raw material as converted U3O8, formally known as Uranium Hexafluoride (UF6). The purchased UF6 is delivered from the vendor to the Enricher via a book transfer to I&M's account. After the UF6 has been enriched to I&M's specifications, the enriched material is then book transferred to the fabricator into I&M's account. The Fabricator then fabricates fuel assemblies per I&M's specifications, specifically designed for delivery to each unit. These final fabricated fuel assemblies are then transported to DC Cook marking the only point that material is in I&M's possession on site. These fuel assemblies are brought on site to be receipt inspected approximately a month prior to a unit's scheduled refueling outage (approximately every 18 months). There are a total of 193 fuel assemblies in each unit's core design. Every refueling outage DC Cook replaces a batch of fuel assemblies, which consists of approximately 80-88 new fuel assemblies. A batch will remain in the core for up to 54 months depending on the unit's generation schedule.

6.4.8 Specific Units

The DC Cook Nuclear Plant is located on 650 acres along Lake Michigan's eastern shoreline in Berrien County, Michigan. The plant is owned and operated by I&M. At full power, the two units can generate enough electricity for more than 1.5 million homes.

DC Cook Unit 1 initial criticality was in January 1975 and is currently licensed to run until October 2034. The Unit 1 core holds a total of 193 fabricated fuel assemblies. This unit has a nameplate rating of approximately 1,100 MW.

DC Cook Unit 2 initial criticality was in March 1978 and is currently licensed to run until December 2037. The Unit 2 core holds a total of 193 fabricated fuel assemblies. This unit has a nameplate rating of approximately 1,200 MW.

6.4.9 Procurement Process

In developing contracts and making purchases, I&M carefully plans the lead time required to perform each phase of the fuel process. The target date from which decisions are made is the date the fabricated fuel is needed at the DC Cook. Once the target date is established, it is then necessary to identify when the fabricator must have the enriched uranium. I&M continuously monitors the long term generation schedule to determine any impacts to fuel procurement activities. All material delivered during the procurement process is delivered on the contractually obligated date to the designated facility. This process reduces the overall cost of refueling the reactors.

6.4.10 Contract Descriptions

I&M's procurement needs are broken down into three main categories of contracts based on the procurement process (Raw Material or Uranium, Enrichment and Fabrication).

I&M has Master Services Agreements (MSA's) in place with multiple Uranium vendors from across the United States, Canada and Europe for the purchase of Uranium. These MSA's provide flexibility to purchase UF6 from multiple vendors from various parts of the world providing I&M a diverse level of supply and creates pricing competition. Per contractual terms, all material must meet the American Society for Testing and Materials (ASTM) "standard specifications for Uranium Hexafluoride for Enrichment for commercial natural UF6" as defined in the current specifications in effect. I&M currently has contracted material to provide DC Cook with the vast majority of raw material that will be needed based on the current generation forecast through 2025.

I&M currently has one long term contract for enrichment that will cover all needs for both Units at DC Cook that is extendable through the current end of the plant life. Per contractual terms, all enriched uranium shall conform to the definition of "enriched commercial grade UF6" per the latest ASTM "standard specification for Uranium Hexafluoride Enriched to Less Than 5%". This contract provides 100% of all the enrichment needs for DC Cook and is adjusted based on the generation forecast as it is updated.

I&M currently has one long term fabrication contract that will cover all needs for both Units at DC Cook through the current end of life of the plant. I&M fabricated fuel assemblies comply with the NRC license. This includes an approved Quality Assurance Program that requires the procurement of nuclear fuel from vendors with approved Quality Assurance programs which meet federal regulations. These Quality Assurance Programs are intended to control the design and manufacturing process to assure a product of the highest quality. This contract provides 100% of all final fabricated fuel assemblies needed to refuel the units on an approximately every 18 month basis and is adjusted based on the generation forecast as it is updated.

6.4.11 Excess Inventory

Excess inventory (or remaining account balances at the Enricher & Fabricator) fluctuates depending on the timing of the reload batch to be delivered. Small amounts of residual inventory balances do exist as a result of final detailed fuel cycle and fuel assembly design. I&M continually monitors the performance of any vendor who is under contract to assure fulfillment of contractual obligations. By contracting with reliable and proven performers and continuously monitoring their performance, the Company can operate with confidence at a lower inventory level.

Operating at a relatively low inventory and utilizing the spot market allows I&M to take advantage of the secondary market and reduce fuel-carrying costs. I&M also optimizes the scheduling of purchases to coincide with material requirements and contract flexibility in order to hold a relatively low inventory.

6.4.12 Forecasted Fuel Prices

I&M-specific forecasted annual fuel prices, by unit, for the period 2021 through 2050 are displayed in Appendix Volume 3, Exhibit B (Confidential).

6.5 Environmental Issues and Implications

It should be noted that the following discussion of environmental regulations is based on the requirements currently in effect and those compliance options viewed as most likely to be implemented by the Company. Activity including but not limited to Presidential Executive Orders, litigation, petitions for review, and Federal Environmental Protection Agency (EPA) proposals may delay the implementation of these rules, or alter the requirements set forth by these regulations. While such activities have the potential to materially change the compliance options available to the Company in the future, all potential outcomes cannot be reasonably foreseen or estimated.

6.5.1 Clean Air Act Requirements

The Clean Air Act (CAA) establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements. The primary regulatory programs that continue to drive investments in AEP operating companies' existing generating units include: (a) periodic revisions to National Ambient Air Quality Standards (NAAQS) and the development of state implementation plans to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under the Mercury and Air Toxics Standard (MATS) rule, (d) implementation and review of Cross-State Air Pollution Rule (CSAPR), a federal implementation plan designed to eliminate significant contributions from sources in upwind states to non-attainment or maintenance areas in downwind states and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil fueled electric generating units under Section 111 of the CAA.

Notable developments in significant CAA regulatory requirements affecting the Company's operations are discussed in the following sections.

6.5.2 National Ambient Air Quality Standards

The Federal EPA issued new, more stringent NAAQS for particulate matter (PM) in 2012 and ozone in 2015. After review, in December 2020, the Federal EPA announced it will retain both standards without change. The existing standards for NOx and SO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of all of these standards is underway.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA confirmed that the CSAPR program satisfied all interstate transport obligations associated with the 2008 ozone standard, but that finding was reversed by the U.S. Court of Appeals for the D.C. Circuit. That court also remanded the 2015 secondary ozone standard and is reviewing Federal EPA's 2018 rule governing implementation of the 2015 ozone standard. The Federal EPA completed external review drafts of the integrated science assessment and policy assessment for the ozone standard in 2019. Any further changes will require additional rulemaking.

6.5.3 Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on SO_2 and NOx allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NOx budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule, the CSAPR Update, to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The CSAPR Update significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. The rule was challenged in the courts and in 2019, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy and should have considered whether there were available measures to control emissions from sources other than generating units. In early 2021, EPA finalized a Revised CSAPR Update Rule to address the Court's concerns. The proposal reduced the Ozone Season NOx budgets of 12 states beginning in 2021.

6.5.4 Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of Hazardous Air Pollutants (HAPs) from coal and oil-fired power plants. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. Compliance was required within three years. The Company obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Industry trade groups and several states filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change. A final rule adopting the findings in the proposal was issued in April 2020. The rule has been challenged in the U.S. Court of Appeals for the District of Columbia Circuit.

I&M's Rockport Plant is located in Rockport, Indiana and consists of two similar coal fired generating units fired with pulverized coal. Units 1 and 2 at the Rockport Plant were placed in service in 1984 and 1989, respectively, and have been efficient and reliable performers for I&M and its customers. For over thirty years, the Rockport Plant has been a cornerstone of I&M's generation fleet and has achieved low emission rates of nitrogen oxides (NOx) and SO_2 by consuming predominantly low-sulfur coal from the Powder River Basin (PRB). Each unit is equipped with an Electrostatic Precipitator (ESP) for collection of particulate matter (PM, also referred to as fly ash); low-NOx burners (LNB) with overfire air (OFA) to minimize the formation of NOx during combustion; Activated Carbon Injection (ACI) for the capture of mercury emissions; and Dry Sorbent Injection (DSI) for the reduction of acid gases and sulfur dioxide (SO_2) removal. In addition, Selective Catalytic Reduction (SCR) technology has been installed on Rockport Unit 1 and Rockport Unit 2. These SCR installations will further reduce Rockport's NOx emissions.

Each unit at the Rockport Plant currently consumes a blend of approximately 87% PRB sub-bituminous coal and 13 percent eastern bituminous coal. This high percentage PRB blend results in lower emission rates of SO_2 and NOx relative to burning 100 percent eastern bituminous coal.

6.5.5 Climate Change, CO_2 Regulation and Energy Policy

In 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil fuel-fired steam generating units and combustion turbines, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

The final rules were challenged in the courts. In 2016, the U.S. Supreme Court issued a stay on the final CPP, including all of the deadlines for submission of initial or final state plans, pending a final decision by the U.S. Court of Appeals for the District of Columbia Circuit and any petitions for review to the U.S. Supreme Court. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance and issued a final rule repealing the CPP in 2019. The cases were then dismissed.

In 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule replacing the CPP with new emission guidelines for regulating CO_2 from existing sources. The ACE rule required states to evaluate the applicability and effect of implementing specific heat rate improvement measures at coal-fired generating units, and to develop a standard of performance for each affected unit within their jurisdiction. State plans were due in July 2022; however, in January 2021, the U.S. Court of Appeals for the D.C. Circuit vacated the ACE rule and remanded it to the Federal EPA. It is too soon to predict how the Federal EPA will respond to the court's remand.

In 2018, the Federal EPA also proposed to revise the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. That rule has not been finalized.

For purposes of this Integrated Resource Plan, as described later, I&M conducts analyses around carbon regulation by evaluating scenarios with costs associated with potential future carbon regulations.

6.5.6 New Source Review (NSR) Settlement

On October 9, 2007, AEP's eastern companies entered into a consent decree with the Department of Justice to settle all complaints filed against AEP's affiliates, including I&M. Under the original Consent Decree, I&M was required to retrofit SCR and FGD technology on Rockport Units 1 and 2 by December 31, 2017, and December 31, 2019, respectively.

On February 22, 2013, the parties filed a proposed Third Modification to the Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. This modified Consent Decree authorized I&M to install dry sorbent injection (DSI) technology on both Rockport Units by April 16, 2015, and deferred the installation of higher efficiency FGD technology on these two units until December 31, 2025, and December 31, 2028. The installation of SCR technology on Rockport

Units 1 and 2 by December 31, 2017, and December 31, 2019, respectively, was still required under the modified Consent Decree.

The modified Consent Decree also established annual tonnage limits for SO_2 for the Rockport Plant. These annual station-wide caps are displayed in Table 6.

Table 6. Modified Consent Decree Annual SO_2 Cap for Rockport Plant

Calendar Year	Annual Tonnage Limitations for SO_2
2016	28,000
2017	28,000
2018	26,000
2019	26,000
2020 – 2025	22,000
2026 – 2028	18,000
2029, and each year thereafter	10,000

In 2019, the parties to the Consent Decree entered into a Fifth Joint Modification to authorize I&M to enhance the DSI systems and achieve the 10,000 ton per year cap on emissions at the Rockport Plant beginning in calendar year 2021. The parties also agreed to extend the date to complete the SCR installation at Rockport Unit 2 until June 1, 2020, to facilitate the DSI work to be completed during the same outage. Rockport Unit 1 will retire at the end of 2028, and the SO_2 emissions cap at Rockport Plant will decline to 5,000 tons per year. The Rockport Units will also achieve a 30-day rolling average SO_2 emissions rate of 0.15 lbs/MMBtu and a 30-day rolling average NOx emission rate of 0.090 lbs/MMBtu at the combined stack, beginning in calendar year 2021.

6.5.7 Coal Combustion Residual Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of Coal Combustion Residuals (CCR), including fly ash and bottom ash generated at coal-fired electric generating units and FGD gypsum generated at some coal-fired plants. The rule applies to new and existing CCR landfills and CCR surface impoundments at operating electric utility or independent power production facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria, and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. In 2018, some AEP operating company facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at two facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted the Federal EPA's motion. During 2019 and 2020, Federal EPA proposed multiple rulemakings to address the court's decisions and Stakeholder concerns. In August 2019, the Federal EPA published a proposal to revise the beneficial use criteria and definition of CCR piles. In December 2019, the Federal EPA published proposed revisions to implement the court's decision regarding timing for closure of unlined surface impoundments and impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. The Federal EPA also published a proposed federal CCR permit program in February 2020, implementing the Water Infrastructure Improvements for the Nation Act, which will apply in states that do not have a federally approved state CCR program. In March 2020, the Federal EPA published a proposed rule that would allow a facility to make an alternative demonstration to continue operating unlined surface impoundments. In August 2020, the Federal EPA finalized its proposed revisions to the CCR rule to include a requirement that unlined CCR storage ponds cease operations and initiate closure by April 11, 2021. The revised rule provides two options that allow facilities to extend the date by which they must cease receipt of coal ash and close the ponds.

The first option provides an extension to cease receipt of CCR no later than October 15, 2023, for most units, and October 15, 2024, for a narrow subset of units; however, the Federal EPA's grant of such an extension will be based upon a satisfactory demonstration of the need for additional time to develop alternative ash disposal capacity and will be limited to the soonest timeframe technically feasible to cease receipt of CCR.

The second option is a retirement option, which provides a generating facility an extended operating time without developing alternative CCR disposal. Under the retirement option, a generating facility would have until October 17, 2023, to cease operation and to close CCR storage ponds 40 acres or less in size, or through October 17, 2028, for facilities with CCR storage ponds greater than 40 acres in size.

Under both the first and second options, each request must undergo formal review, including public comments, and be approved by the Federal EPA. AEP's applications are still pending before Federal EPA.

Because AEP operating companies currently use surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Closure and post-closure costs have been included in Asset Retirement Obligation (ARO) in accordance with the requirements in the final rule. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to ground waters that have a hydrologic connection to a surface water body represent an “unpermitted discharge” under the Clean Water Act (CWA). Two cases have been accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. In April 2020, the Supreme Court issued an opinion remanding one of these cases to the Ninth Circuit Court of Appeals based on its determination that discharges from an injection well that make their way to the Pacific Ocean through groundwater may require a permit, if the distance traveled, the length of time to reach the ocean, and other factors make it “functionally equivalent” to a direct discharge from a point source. The second case was also remanded to the lower court.

Prior to the Supreme Court’s decision, the Federal EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to ground water, and issued an interpretative statement considering comments received in the rulemaking docket and determined that “releases to groundwater are excluded from the scope of the National Pollutant Discharge Elimination System (NPDES) program, even where pollutants are conveyed to jurisdictional surface waters via groundwater.” In December 2020, the Federal EPA issued draft guidance for public comment on applying the outcome of the Supreme Court’s decision and consideration of functionally equivalent factors. The impact of these developments on CCR units will be determined by further EPA guidance, additional permitting decisions, and future action from the courts.

6.5.8 Solid Waste Disposal

Prior to 2010, Rockport Plant fly ash was produced and marketed for reuse in applications that included flowable fill, ready mix concrete, raw feed for cement manufacture, and structural fills. Fly ash sales ceased beginning in 2010 because the Activated Carbon Injection system (ACI) to control mercury was placed into service. Fly ash is disposed of at the on-site landfill permitted by the Indiana Department of Environmental Management (IDEM). The landfill is underlain with clay and a geosynthetic plastic liner, has a groundwater monitoring well system that is sampled to monitor for potential impacts to groundwater, and storm-water runoff collection and treatment system, with discharge regulated by an IDEM-issued National Pollutant Discharge Elimination System (NPDES) permit. Unused bottom ash is stored in a pond for future use, which is also regulated by an IDEM NPDES permit.

On December 19, 2014, the US EPA signed the final Coal Combustion Residuals (CCR) Rule which became effective on October 19, 2015. This rule impacts the bottom ash pond and landfill at the Rockport Plant.

Non-hazardous solid wastes generated at Rockport Plant, as well as the hydro facilities, are disposed at permitted municipal solid waste landfills. Typical solid wastes may include general trash, non-hazardous solvents, and hydraulic fluid, which may be recycled or properly disposed of using licensed vendors. These facilities recycle numerous non-hazardous and hazardous wastes, including everything from paper and cardboard to batteries and used mercury.

6.5.9 Hazardous Waste Disposal

Rockport is typically a small-quantity generator of hazardous waste, such as parts washer by-products, batteries, light bulbs, and paints. The plant recycles light bulbs and batteries. Rockport has significantly reduced the amount of solvents generated in the parts washers by purchasing its own equipment and processing its own non-hazardous solvents.

6.5.10 Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants pursuant to section 316(b) of the Clean Water Act that is intended to reduce mortality of aquatic organisms impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. AEP facilities that have had their wastewater discharge permits renewed have been asked to monitor intake flows or to enhance monitoring practices to assure the current technology is being properly managed to ensure compliance with this rule.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines (ELG) for generating facilities. The rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater and remanded them to the Federal EPA for reconsideration. Those standards have not been reissued. In November 2019, the Federal EPA proposed revisions to the standards for FGD wastewater and bottom ash transport water discharges from existing generation facilities. A final rule was published in the Federal Register on October 13, 2020, establishing additional options for reusing and discharging small volumes of bottom ash transport water, provides an exception for retiring units, and extends the compliance deadline to a date as soon as possible beginning one year after the rule is published but no later than December 2025. The Company has assessed technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting for FGD wastewater and bottom ash transport water.

Permit modifications for affected facilities were filed in January 2021 that reflect the outcome of that assessment.

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of “waters of the United States” in light of recent U.S. Supreme Court cases. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. The final replacement rule was published in the Federal Register in April 2020 and became effective in June 2020. The final rule limits the scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, artificial ponds and waste treatment systems. Challenges to the final rule and requests for a preliminary injunction have been brought by states and other groups in multiple U.S. District Courts. At this time, none of the jurisdictions in which AEP operates are impacted by a stay. The Company is monitoring these various proceedings but is unable to predict the actions of the various courts.

In April 2020, the U.S. District Court for the District of Montana issued a decision vacating the U.S. Army Corps of Engineers’ (Corps) General Nationwide Permit 12 (NWP 12), which provides standard conditions governing linear utility projects in streams, wetlands and other waters of the United States having minimal adverse environmental impacts. The Court found that in reissuing NWP 12 in 2017, the Corps failed to comply with Section 7 of the Endangered Species Act (ESA), which requires the Corps to consult with the U.S. Fish and Wildlife Service regarding potential impacts on endangered species. The Court remanded the permit back to the Corps to complete its ESA consultation, and also enjoined the Corps from authorizing any dredge or fill activities under NWP 12 pending completion of the consultation process. The Department of Justice filed a motion to stay the injunction and tailor the remedy imposed by the Court. In May 2020, the Court revised its order lifting the injunction for non-oil and gas pipeline construction activities and routine maintenance, inspection and repair activities on existing NWP 12 projects. The Department of Justice appealed the Court’s decision to the Court of Appeals for the Ninth Circuit and moved for stay pending appeal, which was denied. In June 2020, the Department of Justice submitted an application to the U.S. Supreme Court requesting a stay of the District Court’s Order, and the Court granted the request with respect to all oil and gas pipelines except the Keystone Pipeline. The Company is monitoring the litigation and evaluating other permitting alternatives but is currently unable to predict the impact of future proceedings on current and planned projects.

In September 2020, the Corps issued for public comment the proposed renewal of all General Nationwide Permits. As part of that proposal the Corps has narrowed the focus of NWP 12 to only oil and natural gas pipeline activities. The Corps proposed two new Nationwide Permits governing electric utility line and telecommunications activities, and other utility lines (e.g., conveyance of potable water, sewage, other substances), respectively. In January 2021, the Corps issued 16 final Nationwide Permits, including NWP 12 and the two new utility line permits, NWP 57 and NWP 58. The Corps chose not to reissue or modify the remaining Nationwide Permits at this time. The 2017 versions of those permits remain in effect. Management is currently assessing impacts of the rulemaking on current and planned projects.

6.6 Demand-Side Programs

6.6.1 Background

Demand-Side programs, also known as Demand-side Management (DSM) collectively includes utility programs aimed at influencing both the level of, and timing of, customer use of grid supplied electricity. These types of programs are structured to counter the ongoing need for increased supply resources through customer energy conservation or direct intervention in how customers use electricity. Typically, customer influence is achieved through some form of monetary or product enticement either through utility rebates or electric bill credit payments. Several demand-side programs are available including Energy Efficiency (EE), Demand Reduction (DR), Conservation Voltage Reduction (CVR) and Distributed Generation (DG). Rate design can also influence customers' energy consumption behaviors.

Generally, EE programs pay rebates directly to customers that are designed to encourage either end-use conservation or energy use reduction through the installation of or upgrade to more efficient end-use technologies. Some EE programs do not pay a cash rebate but instead encourage customers to reduce their annual energy consumption, or better manage their cost of electricity. Other types of EE programs seek to influence the manufacture and supply of more efficient end-use technologies through upstream rebate payments to end-use technology providers that reduce the technology cost to end-use customers. EE programs provide both energy and demand savings. Energy savings are accounted for as an around-the-clock energy reduction impact while demand savings are accounted for in terms of their point-in-time, peak coincident use reduction on an hourly basis.

Generally, DR programs offer electric bill credits through tariff pricing mechanisms to elicit point-in-time energy use reductions (also known as demand, or coincident peak demand reductions). DR programs require specific action to monitor and control electricity use during periods of peak usage. Direct load control (DLC) programs allow utility control over customers' end use loads to achieve the specific peak period use reduction. Other types of DR programs allow customers to reduce use during peak periods on their own accord and pay bill credits based on the actual level of usage during peak period events. Demand response programs primarily provide peak coincident demand impacts but can provide energy impacts as well depending upon the extent of use reduction that occurs.

DG typically refers to small-scale customer-sited generation behind the customer meter. Common examples are Combined Heat and Power (CHP), residential and small commercial solar applications, and even wind. Currently, these sources represent a small component of demand-side resources, even with available federal tax credits and tariffs favorable to such applications. I&M's retail jurisdictions have "net metering" tariffs in place which currently allow excess generation to be credited to customers at the retail rate up to the amount of the customer's monthly bill.

CVR (a.k.a. Electric Energy Consumption Optimization (EECO) or Volt-VAR Optimization (VVO)) is a process by which the utility systematically reduces voltages in its distribution network through the installation and use of sensors and controllers on the grid, resulting in a proportional reduction of load on the network. This voltage reduction still maintains minimum levels needed by customers but elicits lower energy use from end-use customer appliances without any changes in behavior or changes to appliance efficiencies.

Rate design is expected to become an increasingly important element of future utility regulation and resource planning as the industry changes, particularly in the way electricity is supplied and used, as well as the times at which energy is produced and used. As an example, increasing levels of DERs, EVs, and overall electrification of the economy will have significant and uncertain impacts on electric demand, supply, and use. The full deployment of AMI technology will provide useful and necessary information to better evaluate and disaggregate loads and support future rate design changes. In general, the Company's approach to rate design changes is two-fold: 1) test rate design concepts with small scale or limited-scope offerings; and 2) include proposals in its base rate or other proceedings in order to allow other parties, commission staff, and commissions to evaluate the reasonableness of such proposals. As this area of the business evolves, I&M anticipates incorporating those learnings and developments in future IRPs.

6.6.2 Existing Demand-Side Programs

Included in the load forecast discussed in Section 5 of this Report are the demand and energy impacts associated with I&M's DSM programs approved in Indiana and Michigan prior to preparation of this IRP. A summary of these include:

- Energy Efficiency (EE): I&M currently has approved EE programs in place in its Indiana and Michigan service territories. These programs are forecasted to reduce peak demand in 2021 by approximately 2.5 MW and reduce energy consumption by approximately 13.3 GWh.
- Demand Reduction (DR): DR programs are accounted for as a load shape reduction from the load forecast used in the IRP. For the year 2023, I&M anticipates 204 MW of DR reduction. The majority of this DR is achieved through interruptible load agreements. A smaller portion is achieved through direct load control.
- Distributed Generation (DG): Through November 2020, the Company has 818 customers that have installed net metering and or co-generation qualifying customer-generation facilities which are interconnected and/or net metered with a total nameplate capacity of approximately 17.966 MW.
- CVR: I&M currently has 65 distribution circuits with CVR installed in its Indiana service territory and three distribution circuits in its Michigan jurisdiction.

6.7 AEP-PJM Transmission

6.7.1 General Description

The AEP eastern transmission system (Eastern Zone) consists of the transmission facilities of the eleven eastern AEP operating or Transmission companies including I&M, Appalachian Power Company (APCo), Ohio Power Company (OPCo), Kentucky Power Company (KPCo), Wheeling Power Company (WPCo), Kingsport Power Company (KgPCo), AEP Appalachian Transmission Company [APTC], AEP Indiana Michigan Transmission Company (IMTC), AEP Kentucky Transmission Company (KYTC), AEP Ohio Transmission Company (OHTC), and AEP West Virginia Transmission Company (WVTC). The Eastern Zone is composed of approximately 14,950 miles of circuitry operating at or above 100kV and includes over 2,120 miles of 765kV transmission lines overlaying 3,550 miles of 345kV lines and over 9,000 miles of 138kV circuitry. This expansive system allows the economical and reliable delivery of electric power approximately 21,610 MW of customer demand connected to the AEP eastern transmission system that takes transmission service under the PJM open access transmission tariff.

The transmission line circuit miles in I&M's Indiana service territory include approximately 610 miles of 765kV, 1,400 miles of 345kV, 1,560 miles of 138kV, 490 miles of 69kV, and 315 miles of 34.5kV lines. I&M's Michigan service territory includes approximately 16 miles of 765kV, 234 miles of 345kV, 240 miles of 138kV, 300 miles of 69kV, and 85 miles of 34.5kV lines.

The AEP eastern transmission system is part of the Eastern Interconnection, the most integrated transmission system in North America. The entire AEP eastern transmission system is located within the Reliability*First* Corporation (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization (RTO) and now participates in PJM regional planning, operations and markets.

The AEP eastern transmission system can be influenced by both internal and external factors from its geographical location, expanse, and numerous interconnections. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern transmission system conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

AEP's eastern transmission system assets are aging. Figure 21 below demonstrates the development of that Transmission Bulk Electric System. In order to maintain reliability, significant investments will be necessary over the next decade to address the aging infrastructure and assets. Despite the robust nature of the eastern transmission system, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits.

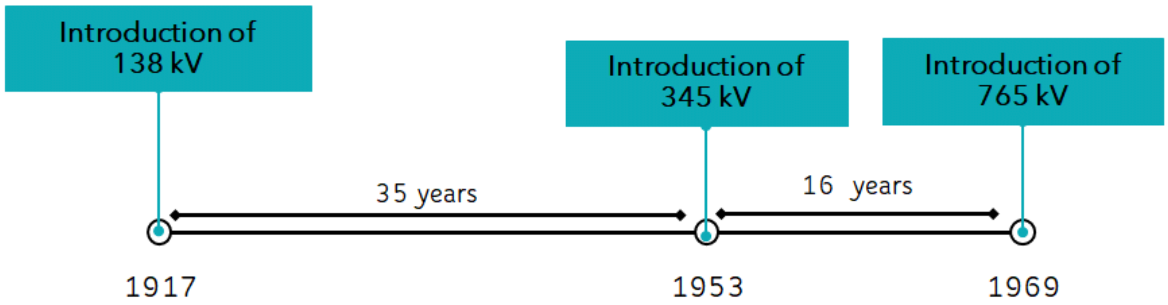

Figure 21. AEP Eastern Transmission System Development Milestones

Over the years, AEP, and more recently PJM, entered into numerous study agreements to assess the impact of the connection of potential generation to the eastern transmission system. AEP companies, in conjunction with PJM, have interconnection agreements in their service territories with several plant developers. Other generation additions are planned to be connected to the eastern transmission system over the next several years (including upgrades to existing facilities, once studied and approved through the PJM Generation Interconnection queue process[12]) and additional generation is under study for potential interconnection.

The integration of the generation now connected to the eastern transmission system required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and adjacent markets, such as MISO and NYISO.

6.7.2 Transmission Planning Process

AEP and PJM coordinate the planning of the transmission facilities in the AEP Eastern Zone through a “bottom up/top down” approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM’s transmission planning process. PJM will incorporate AEP’s expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement and Attachment M-3 of the PJM tariff. By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional

[12] PJM Generation Interconnection queue is located at: https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

planning process that considers both regional and local needs and solutions, thus ensuring a consistent view of needs and expansion timing while minimizing expenditures. When regional system upgrade requirements are identified under the RTEP, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable, and economical integrated transmission reinforcement plan for the entire region, while blending the local planning expertise of the transmission owners such as I&M with a regional view and formalized open Stakeholder input.

AEP's transmission planning criteria are consistent with North American Electric Reliability Corporation (NERC) and RFC reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 and these planning criteria are posted on the AEP website.[13] Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address anticipated deficiencies.

Similarly, AEP also identifies local needs and solutions through the Attachment M-3 planning process that drives Supplemental and asset management projects in the RTEP. All projects affecting the topology of the grid, whether PJM identified or Transmission Owner identified (TO Projects), are subject to the stakeholder process within PJM. While PJM does not formally "approve" TO Projects, these projects are submitted to PJM and reviewed with the Transmission Expansion Advisory Committee (TEAC) and Subregional RTEP Committee – Western on a periodic basis in accordance with the provisions in Attachment M-3 of the PJM Tariff. All TEAC and Subregional RTEP Committee-Western meetings are open and any transmission stakeholder can attend. TO Projects are subject to multiple rounds of review and detailed project information, including needs and alternative solutions. The Attachment M-3 process ensure stakeholders have an opportunity to review TO Projects and include the following meetings and posting requirements:

- Separate stakeholder meetings to discuss:
    - Criteria, assumptions and models used to plant TO Projects (Assumptions Meeting);
    - Needs underlying TO Projects (Needs Meeting); and,
    - Potential solutions to meet those needs (Solutions Meeting).
- Posting of criteria, assumptions, and models at least 20 calendar days prior to the Assumptions Meeting and accepting post-meeting comments for ten days after this meeting;
- Posting of criteria violations and drivers at least ten days in advance of the Needs Meeting and accepting post-meeting comments for ten days after this meeting;
- Posting of potential solutions and alternatives identified by PJM Transmission Owners or stakeholders at least ten days in advance of the Solutions Meeting and accepting post-meeting comments for ten days after this meeting; and,

13 https://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/

- Opportunity to submit final comments for PJM Transmission Owner review and consideration at least ten days before the Local Plan is integrated into the RTEP.

PJM also coordinates its regional expansion plan on behalf of the member utilities with neighboring utilities and/or RTOs, including the MISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the MISO provides for joint transmission planning.

6.7.3 System-Wide Reliability Measures

Transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system. The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

6.7.4 Evaluation of Adequacy for Load Growth

As part of the on-going near-term/long-term planning process, AEP and PJM use the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, PJM and AEP seek solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission project reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[14] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

6.7.5 Evaluation of Other Factors

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in

14 90% probability that the actual peak load will be lower than the forecasted peak load and 10% probability that the actual peak load will be higher than the forecasted peak load.

AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually be connected to the transmission system is unknown at this time.

6.7.6 Transmission Expansion Plans

The transmission system expansion plans for the AEP eastern transmission system are developed and reviewed through the PJM Stakeholder process to meet projected future requirements. AEP and PJM use power flow analyses to simulate normal conditions, and credible contingency scenarios to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP, in coordination with PJM, will continue to develop transmission reinforcements to serve its own load areas to ensure compatibility, reliability and cost efficiency.

6.7.7 Transmission Project Descriptions

A list and discussion of transmission projects that have recently been completed, are presently underway or planned in the I&M service area can be found in Section 6.7.9 of this report. In addition, several other projects beyond the I&M service territory have also been completed or are underway across the AEP Eastern Zone. While they do not directly impact I&M, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefit Indiana customers.

AEP's eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M's customers in Indiana and Michigan. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

6.7.8 FERC Form 715 Information

A discussion of the AEP Eastern Zone reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's 2021 FERC Form 715 Annual Transmission Planning and Evaluation Report, which can be found in Appendix Volume 3, Exhibit A. That filing also provides pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system.

As the transmission planner for AEP and AEP eastern subsidiaries, including I&M, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all transmission owners, including AEP and its subsidiaries. Information about current cases, models, or results can be requested from

PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, and neighboring companies themselves. In general, sufficient detail is obtained to adequately assess all events, outages, and changes in generation dispatch, which are contemplated in any given study.

6.7.9 Transmission Project Details

AEP’s eastern transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M’s customers.

A list with a brief description of scope of certain I&M transmission projects that have either recently been completed, are presently underway, or planned, is provided below. These projects contribute to the robust health and capacity of the overall transmission grid, which benefits all customers.

- **Central South Bend Reliability Project:** Transmission planning is proposing to construct 2.5 miles of 69 kV underground transmission line in South Bend to address rehab and operational needs. This enables the retirement of Colfax – Kankakee 34.5kV line and conversion of the South Bend – West Side 34.5kV Line and the South Bend – Colfax 34.5kV line to 69kV operation as majority of the lines are built to 69kV standards but operate at 34.5kV. Converting the system to 69kV will address the operational switching concerns. Colfax and Drewry’s Station will be complete station rebuilds because of asset renewal, space limitation and operational needs. St Mary’s Station has some rehab needs and will be upgraded to accept 69kV service.

   - 2021: $10.1 million
   - 2022: $5.8 million
- **College Corner 138kV Rebuild:** AEP has identified multiple asset renewal issues at the College Corner station including FK oil-type breakers. AEP is rebuilding College Corner in an adjacent location and replacing a breaker at the Richmond remote end station.
   - 2021: $4.1 million
- **Dragoon – Kline Improvements:** AEP transmission will expand the existing Dragoon station, upgrade all switches along the 34.5kV corridor going from Dragoon to Kline, upgrade Russ St. switch, and rebuild a quarter mile of the existing South Bend – Dragoon 34.5kV line. The 138kV hard tap will be eliminated and the 138kV yard will be reconfigured with an in and out configuration, install a 138kV bus tie circuit breaker, install a second 138/69/34.5 autotransformer, and replace four 34.5kV circuit breakers. Transmission will also upgrade risers at Kline and Virgil St. Stations.
   - 2021: $0.6 million
   - 2022: $3.6 million
   - 2023: $1 million
- **Eugene – Dequine – Meadow Lake Upgrades:** This project will reconductor 45 miles of 345kV line between Eugene and Dequine stations, and reconductor 14 miles of 345kV line between Dequine and Meadow Lake stations. Multiple overloads were identified by PJM during its 2015 and 2016 regional transmission expansion plan. This project would address all overloads identified by PJM.
   - 2021: $2 million
   - 2022: $0.8 million
- **SDI Service Enhancements:** This project is to construct a new 138 kV switching station between Grabill and South Hicksville, extend a greenfield 138 kV line (~3.5 miles) from this station to Butler-North Hicksville line, and construct a new greenfield 345/138 kV station near SDI South Butler and Wilmington. From this 345/138 kV station, a greenfield double circuit 138 kV line (~1.5 miles) will be extended to Auburn-Ferrous line near New Millennium. From New Millennium, a greenfield single circuit 138 kV will be extended to Butler-North Hicksville line and loop into the new 345/138 kV station, and a single 345kV line will be built toward the South Butler delivery point. Collingwood and Dunton Lake 345kV substations will be combined on the site of Dunton Lake and will support two feeds to South Butler station. This project will address the 300MW load loss criteria violation at South Butler station.
   - 2021: $7.1 million
- **Valley Area Reinforcements:** AEP is rebuilding the Valley – Glenwood Tap, Riverside – South Haven and Almena – Hartford line to 69kV standards and the Valley – Almena line will be rebuilt as a 138/69kV double circuit line. Almena station will need to have a 138kV high side installed to incorporate this new line. Hartford station will have a 138/69kV transformer added with high

and low side protection to provide another source for the network. In addition to this, work is being done at Hartford, Riverside and Hagar station to address aging infrastructure needs.

  - 2021: $2.1 million
  - 2022: $2.1 million

- **Southern Muncie:** AEP will be rebuilding the Hogan – 23rd street line as well as replacing significant assets in 23rd Street, Arnold Hogan, Medford and Blaine Street stations and will be installing the new Fuson station which will allow the retirement of Elmridge station.
  - 2021: $3.7 million
  - 2022: $0.2 million
  - 2023: $2.0 million
  - 2024: $1.0 million
- **Western Fort Wayne Improvement:** This project will address thermal and voltage T.O. violations by replacing aging infrastructure and upgrading facilities. A new Snapper Station will replace Churbusco and Carroll stations and Whitley will be rebuilt and converted to 69kV. The Wallen-Whitley 34.5kV circuit will be retired and replaced with 69kV service from Wallen-Snapper 69 kV (via Eel River), Snapper-Whitley 69 kV (via Union) and Whitley-Gateway 69 kV.
  - 2021: $0.9 million
  - 2022: $5.5 million
  - 2023: $1.2 million
- **Hartford City Area Improvements:** Network-wide overloads were identified in the Hartford City 69kV network. AEP is rebuilding the Hartford City – Armstrong line as Hartford City – Jay and building a new Armstrong Cork – Jay 2 line. In addition, AEP is rebuilding Bosman – Delaware as the 69kV Royerton – Strawboard. To accommodate this work, station work will be completed at Jay, Bosman, Strawboard, Hartford City, Royerton and Delaware stations.
  - 2021: $3.1 million
  - 2022: $3.1 million
- **Berrien Springs Area Improvements:** The introduction of a new 138kV source (Blossom Trail) near Eau Claire, MI will provide the opportunity to strengthen the grid and restore stability to the area. In addition, converting the line from Derby through Berrien to 69 kV will further strengthen this area. This project will replace several circuit breakers. The area improvements will transfer some load to a new station, Boxer.
  - 2021: $2.5 million
  - 2022: $1.0 million
- **Northern Muncie Area Improvements:** The Delaware 34.5kV station, the Delaware – Jay 20 mile 34.5kV line and the Delaware – Haymond 2.5 mile 34.5kV line have all been identified as rehab candidates. AEP is installing a new 138kV Perch station and retiring the 20-mile Delaware – Jay asset. AEP will also be rebuilding the Delaware – Haymond line as well as rebuilding the Delaware 34.5kV station as a ring bus to address the issues identified.

    - 2021: $4.0 million
    - 2022: $1.2 million
    - 2023: $0.4 million
- **Strawton Area Improvements:** AEP plans to upgrade the network to 69kV which will allow for retirement of a sizable portion of the remaining 34.5kV assets in the area.
    - 2021: $5.2 million
    - 2022: $1.3 million
- **Western Marion Area Improvements:** AEP has identified condition and performance issues spread throughout the Western Marion area. In order to address these issues, AEP will be rebuilding the Grant – Marion and Deer Creek – Marion lines, rebuilding the Deer Creek 34.5kV voltage class, retiring the Deer Creek – Miller Ave line and will be adding a 138kV cap bank at Grant to maintain voltage levels.
    - 2021: $0.6 million
    - 2022: $1.6 million
- **Hamilton Area Improvements:** Two-way service will be provided to Hamilton and customers by installing a new 69kV line to Butler in order to address Hamilton Station customer outages due to maintenance, storm outages, and fault load dropping on the radial line from Butler. Customers will be served from a new breaker-and-half Teutsch Station and the existing Butler Station will be retired, eliminating exposure to line faults. A new 69kV circuit breaker will replace the motor operated breaker switches (MOABs) at Hamilton.
    - 2021: $0.1 million
    - 2022: $1.3 million
    - 2023: $2.0 million
    - 2024: $0.1 million
- **Hillcrest – Adams 69kV Line Rebuild:** AEP has identified overload criteria violations and multiple condition and performance needs on Hillcrest-Adams 69kV. Ferguson station will be rebuilt on the nearby 138kV line as Baer to move it out of the FAA flight path. The Ferguson – Bluffton 69 kV Branch and Adams – Bluffton 69kV Line will be rebuilt and re-routed to accommodate Kinnerk station served out of Hillcrest station via 3.55 miles radial line and Uniondale (REMC) station served out of Kingsland station via 4.3 miles radial line. Oil filled circuit breakers at Kingsland Station, manufactured in 1969, will be replaced with new circuit breakers.
    - 2022: $0.3 million
    - 2023: $0.6 million
    - 2024: $2.4 million
    - 2025: $0.8 million
- **Robison Park – South Hicksville 69kV Line Rebuild:** AEP has identified condition and performance issues on the Robison Park-South Hicksville 69kV line and a thermal violation for N-1-1 type contingency will be mitigated by rebuilding 2.2 miles of the North Hicksville – Butler 69kV line and 33.22 miles of the South Hicksville – Robison Park Tie 69kV line.

  - 2021: $0.1 million
  - 2022: $0.3 million
  - 2023: $1.0 million
  - 2024: $2.5 million
- **Eastern Marion Improvements:** This project is rebuilding 17.67 miles of the Deer Creek – Hartford City 69 kV line, retiring the Deer Creek – Hummel Creek 34.5kV line, retiring the Jonesboro – Gas City 34.5kV line, retiring the Jonesboro Extension 34.5kV line, retiring the remaining Deer Creek – Alexandria 34.5 kV line (2.2 miles), retiring the de-energized Deer Creek Extension 34.5 kV line and upgrading Hummel Creek station to address equipment material condition, performance and risk issues in Marion, Indiana.
  - 2021: $3.4 million
  - 2022: $1.7 million
  - 2023: $2.8 million
  - 2024: $3.4 million
- **Arnold Hogan - Kenmore 34.5kV Rebuild:** AEP has identified condition and performance issues on the Arnold Hogan-Kenmore 34.5kV line. Rebuilding two miles of the Hogan – Kenmore 34.5kV line will address near overload conditions on the ~.4 mile 336 ACSR portion of the Hogan – Kenmore line that loads up to 98% of its 36MVA rating after the short circuit issue at Christy Woods is resolved. It will also allow AEP to retire several area cap banks in the future.
  - 2021: $7.7 million
- **Western South Bend Area Improvements:** Retiring and converting several lines from 34.5kV to 69kV operation will address aging structures with over 100 open conditions and an N-1-1 type contingency on the New Carlisle-Tulip Road 34.5kV branch. The project will also provide looped service at the 69kV bus such that with loss of the Olive transformer, service can be maintained to the NIPSCO and Harbison loads.
  - 2021: $3.8 million
  - 2022: $0.1 million
- **South Bend – Niles 69kV Line Rebuild:** Planning is proposing to rebuild the 1960's vintage wood cross arm construction along South Bend – Niles 69kV Line which will address the aging infrastructure, system needs as well as open condition concerns on the conductor and structures. The University Park Switch will be replaced as well as the customer metering to the City of Mishawaka. A bus tie breaker will be installed at Swanson Station and the cap switcher will be replaced.
  - 2021: $0.1 million
  - 2022: $0.7 million
  - 2023: $0.6 million
  - 2024: $1.0 million
- **Gateway Area Improvements:** This project will relieve overloads and voltage issues in the Gateway area. To do this, AEP proposes to rebuild the Columbia – Gateway 2 line and the

Columbia – Richland 69kV line as well as rebuilding Columbia station as a 138/69kV station with two transformers.

  - 2021: $1.7 million
  - 2022: $0.9 million

- **Rockport Station Rehab:** This project will replace the 765kV ELF breakers to address compressor failures, open/reclose failures and add a secondary station service source. This project will also expand the control house and replace the roof and HVAC system.
  - 2021: $0.1 million
  - 2022: $0.2 million
  - 2023: $2.7 million
  - 2024: $0.1 million
- **Eastern Melita Area Improvements:** AEP will build new 69kV lines from Melita to Anthony 69kV and a double circuit extension from Lincoln to connect to the Lincoln – Water Pollution 69kV line. A new single circuit 34.5kV Maumee Extension will connect Maumee Sw to the Lincoln – Water Pollution line. Anthony station will be rebuilt as a 69/12kV station, Melita will have a 69kV CB added, and Storm Water, Omnisource, Water Pollution and Lincoln will have minor work done to bring them to 69kV operation. Filtration Switch and the Skid station will be retired.
  - 2021: $0.1 million
  - 2022: $0.1 million
  - 2023: $1.7 million
  - 2024: $2.6 million
  - 2025: $1.7 million
- **Winchester Area Improvements – East:** This project will address planning criteria violations on the Winchester – Anchor Hocking 69kV line and 138/69/12kV Transformer #1 at Randolph station. Supplemental upgrades are also included to expand Randolph, Winchester, and Anchor Hocking stations to address asset performance, equipment condition, risk of failure, and operational flexibility.
  - 2021: $0.3 million
  - 2022: $0.6 million
  - 2023: $6.2 million
  - 2024: $0.2 million
- **Winchester Area Improvements – West:** This project will rebuild 19.1 miles of the Modoc – Winchester 69kV line and Buena Vista – Lynn 69kV lines to address equipment material condition, performance, and risk. The project includes upgrades to expand Modoc and Lynn stations, rebuild Huntsville Switch, and a new switch to serve the tie to Lobdell Station. Asset performance, equipment condition, risk of failure, and operational flexibility warrant the upgrades.
  - 2021: $0.9 million
  - 2022: $1.5 million

  - 2023: $0.2 million

- **Niles Area Reinforcements:** To address condition and performance issues as well as thermal and area voltage contingency issues AEP is proposing a large area solution that will rebuild and reinforce the 69kV sources in the Niles, MI area and install a new Boundary station to improve operational flexibility and reliability.
  - 2021: $1.3 million
  - 2022: $5.0 million
  - 2023: $8.1 million
  - 2024: $3.9 million
  - 2025: $0.2 million
- **Hartford Michigan Area Improvements:** To address condition and performance issues AEP will rebuild the Riverside – Hartford 138 kV line, the Hartford – Bangor 69kV line, and the Bangor – South Haven 69kV line all to current standards. The phase over phase switch at Phoenix Road Tap will also be rebuilt, the Drop in Control Module (DICM) will be expanded and a 69kv circuit breaker at Bangor will be installed for operating and auto-sectionalizing needs.
  - 2021: $2.8 million
  - 2022: $0.3 million
  - 2023: $3.4 million
  - 2024: $3.7 million
  - 2025: $0.2 million
- **I&M SCADA Upgrades:** Supervisory control and data acquisition is being installed at several stations to allow remote monitoring and operation of the system and increase reliability.
  - 2022: $7.9 million

6.8 Distribution Opportunities

6.8.1 Grid Modernization

On an ongoing basis, I&M engages in electric distribution grid planning to ensure safe, reliable and secure development and operation of the distribution energy delivery system. As part of Grid Modernization efforts, I&M is developing policies, procedures, and plans to build the existing energy delivery system into an “enabling platform” that can support Distributed Energy Resource (DER) integration and other new technologies in a safe, reliable, and secure fashion. This enabling platform will facilitate I&M customer owned DER and end-use technology integration for any customer that seeks to interconnect their resources into the distribution energy delivery system, as long as Company interconnection requirements are met and adhered to. To this extent, I&M distribution planning efforts include traditional activities, such as vegetation management, system coordination, system adequacy, distribution hardening and asset sizing. These traditional activities serve as the foundation for a safe, reliable, and secure system. Technology applications, such as distribution automation, advanced metering infrastructure, energy storage, micro grids, and DER integration, are being incorporated into, and applied to, the foundational activities to advance the distribution energy delivery system into an enhanced safe, reliable, and secure system and the enabling platform that customers can interface and interconnect with in a safe, reliable and secure manner.

In order to ensure a safe, reliable, and secure foundation for the distribution energy delivery system, I&M developed plans to first address the leading causes of outages on its system – including, most importantly, vegetation management and aging infrastructure and then layers in distribution automation technology to enhance system capability and operation as part of a Grid Modernization effort. I&M has also initiated efforts to begin development and buildout of the enabling platform concept for DER integration and other advance technology options. Another fundamental aspect of the Grid Modernization plan is that it takes steps to align with both generation and transmission planning.

Grid Modernization recognizes the growth potential for third party distributed energy resources (DERs) and the increased need for active utility monitoring and controls to manage a more dynamic grid. This includes options for non-wires alternatives (NWAs), as well as I&M's progress in developing a process for screening and developing these NWA solutions.

The addition of renewables may lead to more distributed storage capacity on the grid. It is anticipated that these additions will continue to accelerate as FERC Order 2222 matures. Advanced Meter Infrastructure (AMI) and CVR offer both increased visibility into actual distribution system operation and improved system management. CVR provides automated management of system voltage levels and system losses and results in lower aggregate energy usage and peak demand. The combination of these evolutions will result in a grid which is more dynamic and inter-dependent and will require active utility monitoring and controls to manage. An Advanced Distribution Management System (ADMS) with Distributed Energy Resource Management System (DERMS) functionality will allow the Company to implement a new network architecture across AEP. This new network architecture will expand distribution planning criteria listed above, as the load in many instances will no longer be net with the DER energy produced.

The growth of DERs will require further alignment of the planning functions to inform new resource characterization approaches and novel DER sourcing mechanisms. AEP is currently processing a Request for Proposal from several ADMS vendors and will have the vendor / product selected by the end of 2021. Expectations are that a vendor contract, along with Statement of Work (SOW) will be completed Q1 2022, with conversion and systems integration completed by Q4 2023, and production planned for Q1 2024.

6.9 Journey to Fully Integrated Planning Process

I&M believes that continuing to deliver safe, reliable, and affordable energy in the future power system will require an integrated approach between transmission, distribution, and resource planning. For example, local capacity needs that were previously met through transmission-connection generation might be addressed at a lower cost by distributed energy resources. Non-wire alternatives ("NWA") such as microgrid and distributed scale solar and storage might be a lower cost solution to transmission and distribution constraints than new wire assets. Resilience and safety are enhanced with better visibility over future EV deployment and distributed generation at distribution circuit level to allow the planners to plan for multiple load conditions and increase hosting capacity to integrate more green energy generation. Better visibility also allows I&M to better understand locational value of distribution generation across its network which could lead to more efficient pricing and reduce inequities among DER customers.

In meeting its mission in the power system of tomorrow, AEP, has recently created a new Regulated Investment Planning team which brings together under one organization Integrated Resource Planning & Analysis, Transmission Planning & Analysis, Distribution Planning & Analysis, and Interconnection Services. Regulated Investment Planning will plan AEP's regulated infrastructure programs across generation, transmission, and distribution to derive solutions that best meet the needs of customers.

Achieving a fully integrated planning process will require new tools, models, processes, and capabilities. To this end, AEP has engaged an external consultant to evaluate AEP's existing planning tools, models, processes, and capabilities and produce a roadmap for AEP and I&M to achieve fully integrated planning. The project is in progress at the time of this report. In addition to the project, AEP will also continue to leverage new technologies, analytics, and automation as needed to deliver value for all Stakeholders.

7 Modeling Inputs and Assumptions

7.1 Resource Model

The IRP process aims to address the gap between resource needs and current resources. Given the various assets and resources that can satisfy the gap, a tool is needed to sort through the myriad of potential combinations and return an optimum solution. AURORA is the primary modeling application used by I&M and Siemens PTI in the development of this IRP.

AURORA is an industrial standard chronological unit commitment and dispatch model with extensive presence throughout the electric power industry. The model uses a state of the art, mixed integer programing approach ("MIP") to capture details of power plant and transmission network operations while observing real world constraints, such as emission reduction targets, transmission and plant operation limitations, renewable energy availability and mandatory portfolio targets. It is widely used by electric utilities, consulting agencies, and other stakeholders to forecast generator performance and economics, develop IRPs, forecast power market prices, and assess detailed impacts of regulations and market changes affecting the electric power industry. AURORA has gained wide acceptance among electric utility executives, stakeholder groups, and regulatory commissions.

Key inputs to the AURORA model include load forecasts, both supply- and demand-side resource costs and operating characteristics (e.g., heat rates), fuel costs, fixed and variable operating costs, outage rates, emission rates, as well as capital costs. The model assesses the potential performance, fixed and variable O&M costs, and capital costs of prospective and existing generation technologies and resources, and is capable of optimizing resource additions for economic, system reliability, and policy compliance reasons on a utility system, regional or nationwide scale. Outputs of the model include plant generation, gross margin, emissions, and a variety of other metrics. The model also considers transfer limits to reflect transmission constraints.

The AURORA model can be run in several modes. Two were utilized for the 2021 I&M IRP: The Long-term Capacity Expansion model (LTCE) and the Dispatch Simulation model (Dispatch model). The LTCE was utilized to determine the optimal mix of existing and new generating assets that meet demand over time while adhering to regulatory and reliability requirements. The LTCE model was relied on extensively in Step 3 of the IRP Process: Create Candidate Portfolios. All portfolios were optimized based on lowest cost. The Dispatch model was utilized to assess how a portfolio of assets will perform under a fixed set of market conditions. Dispatch results were used to inform Key Performance Indicators used in Step 3 and the stochastic results in Step 4.

Siemens PTI has used AURORA for well over 15 years as its primary model for asset valuation, power market forecasting, and IRP analyses. The model is equipped to analyze portfolio risks by assessing portfolio performance across 200 different future market outlooks. Siemens PTI has developed a sophisticated stochastic framework to ensure that these future market outlooks reflect both relevant historic volatility in key market drivers and cross relationships between different market drivers. Siemens PTI has also developed modules to simulate the different operating characteristics of ISO/RTO regions across the country. For this reason, it is one of the most comprehensive, reliable, and flexible tools in the market for conducting IRPs. Siemens PTI has successfully conducted numerous IRPs for many utilities across the country.

In order to perform the deterministic and probabilistic modeling, AEP provided three fundamental forecast scenarios (a reference case plus a high and low scenario). The AEP reference case forecast, discussed in further detail below as the EIA-based fundamental forecast, served as the basis for the set of Reference Scenario development inputs in Step 3 of the IRP process. The high and the low fundamental forecasts, coupled with the reference forecast, allowed Siemens to develop a set of probability distributions for key market variables from these inputs.

7.2 Fundamental Forecast Process

The AEP EIA-based Fundamentals Forecast is a long-term, weather-normalized commodity market forecast principally based upon the assumptions contained in the EIA's Annual Energy Outlook (EIA AEO). The AEP Fundamentals Forecast is not specific to this IRP analysis; rather, it is made available to AEPSC and all AEP operating companies for various planning and analysis uses. The EIA-based Fundamentals Forecast used for this IRP includes: 1) prices for various qualities of coals; 2) monthly and annual locational natural gas prices, including the benchmark Henry Hub; 3) nuclear fuel prices; 4) sulfur dioxide (SO_2), nitrogen oxides (NOx), and CO_2 burden values; 5) locational implied heat rates; 6) electric generation capacity values; 7) renewable energy subsidies; and 8) inflation factors. The AEP Fundamentals Forecast is also developed using the AURORA model. AEP uses AURORA to produce the zonal level energy forecasts, based on internally defined input components. It is not the same AURORA model that Siemens used as part of the IRP Process.

Figure 22 below describes AEP's EIA-based Fundamentals Forecast components, which were sourced directly from the previously described EIA AEO, third-party energy consultancies, and internally generated information.

Forecast Components	EIA	Other	Source
Economy; Inflation/GDP deflators	✓		EIA Reference case
Generating Reserve Margins		✓	RTO Requirements
Electric Load		✓	AEP Load Forecasting
Electric Load shapes		✓	AEP Fundamentals
Solar/Wind production shapes by area		✓	NREL
Coal; Delivered price to EIA regions	✓	✓	EIA Reference case FOB prices + AEP Fundamentals
Natural gas price; Henry Hub	✓		EIA Reference case
Natural gas price; Locational values	✓	✓	EIA Reference case - Henry Hub + AEP Fundamentals
Natural gas supply; Lower 48 production	✓		EIA Reference case
Natural gas demand (incl. losses)	✓		EIA Reference case
Natural gas; net pipeline/LNG exports	✓		EIA Reference case
Oil price, WTI	✓		EIA Reference case
Fuel Oil price; locational values	✓	✓	EIA Reference case - WTI + AEP Fundamentals
Uranium prices		✓	AEP Fundamentals
Other Fuel(Biofuel, etc...)	✓		EIA Reference case
New gen unit options and capital costs	✓		EIA Reference case
Existing gen units	✓		EIA Reference case
Announced new gen units	✓		EIA Reference case
Aged-out retirements of existing gen units	✓		EIA Reference case
Gen unit maintenance schedule		✓	AEP Fundamentals
Gen unit outages		✓	AEP Fundamentals
Unit-level emission rates; CO_2, SO_2, NO_x		✓	US EPA CEMS data
Application of a CO_2 burden		✓	AEP Environmental
REC		✓	AEP Regulatory Forecast
PTC	✓		EIA Reference case
ITC	✓		EIA Reference case
State-mandated Renewable Portfolio Standards		✓	AEP Environmental
Reporting parameters; Peak/Off-Peak/NERC Holidays		✓	PJM/SPP/other RTO and/or internal guidelines
Transmission/links between Zones		✓	AEP Fundamentals

Figure 22. EIA-based Fundamental Forecast Components

Since the EIA AEO does not provide the granularity for most regulatory applications, AEP's AURORA model was utilized to create a reasonable proxy for the EIA AEO while providing the level of detail necessary for downstream consumption. The AURORA model used by AEP iteratively generates zonal, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions, and capital costs.

The base Fundamentals Forecast employs a CO_2 dispatch burden (adder) on all existing fossil fuel-fired generating units that escalates 3.5% per annum from $15 per metric ton commencing in 2028. This CO_2 dispatch burden is a proxy for the many pathways CO_2 may take (e.g., renewables subsidies/penetration, voluntary and mandatory portfolio standards, low natural gas prices, considerable reduction in battery storage costs) in addition to any regulation to impose fees on the combustion of carbon-based fuels. Additionally, for the Enhanced Regulation Scenario, the Company developed an alternative High CO_2 forecast that accelerates the CO_2 dispatch burden to commence in 2025 at a cost of $40 per metric ton escalated at 5% per year. This is illustrated in Figure 24 below.

The Fundamentals Forecast is not only concerned with the status of regulations and other current conditions that affect prices, but must also reflect reasonable expectations regarding future conditions that affect prices. As such, the carbon price proxy used for fundamentals forecasting is a reasonable assessment of future costs based on the status of carbon regulations and potential changes thereto.

7.3 Key drivers for Candidate Portfolio development

For this IRP, I&M/AEP developed a series of fundamental forecasts of key market drivers for use with Candidate Portfolio development that together represent the expected path forward for each forecasted input variable. Key market drivers included henry hub natural gas prices, powder river basin coal prices, CO2 pricing and capacity prices. As further discussed in section 7.4, AEP and Siemens PTI collaborated on cost and performance characteristics for generating technologies.

7.4 Input Forecasts

Figure 23 to Figure 26 below, shown in 2019 dollars, illustrate the forecasted fundamental parameters (fuel, capacity, and CO_2 emission prices) that were used in IRP Step 3 during the long-term optimization modeling for this IRP. Coal prices did not vary among the different Scenarios.

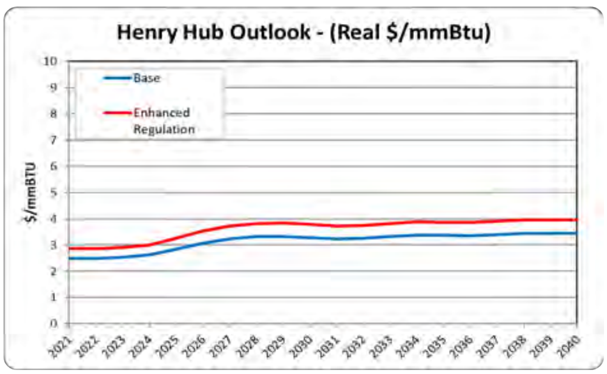

Figure 23. Henry Hub Outlook

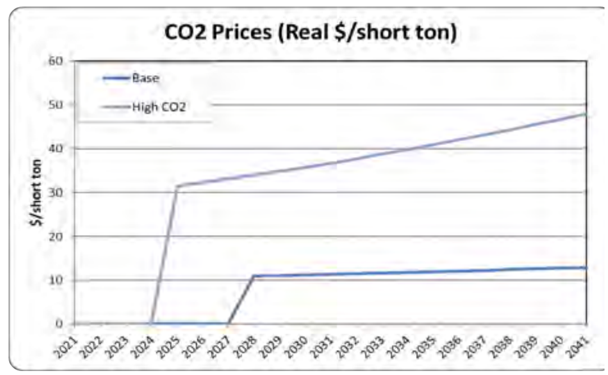

Figure 24. CO_2 Prices

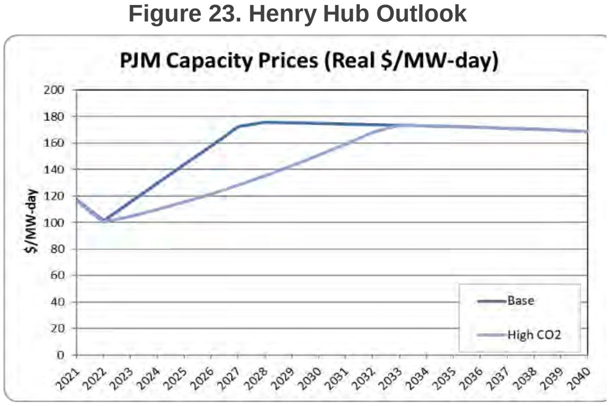

Figure 25. Capacity Prices

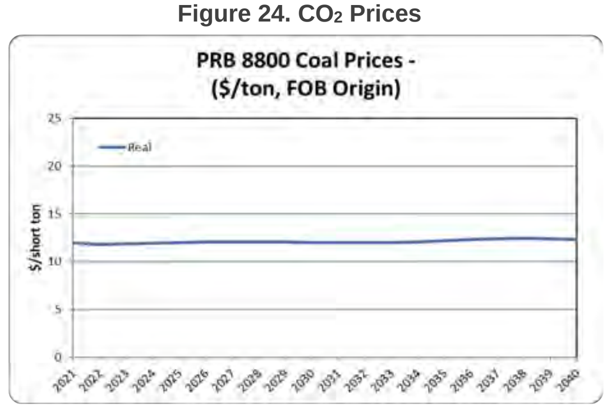

Figure 26. Coal Prices

Scenario on- and off-peak power price forecasts were a modeling output produced by the AURORA dispatch model and informed by the Scenario input assumptions, described in Section 3, along with a view of the greater PJM market. Figure 27 illustrates the energy prices for the Reference Scenario. Energy Prices for the three Scenarios are available in Exhibit C-17.

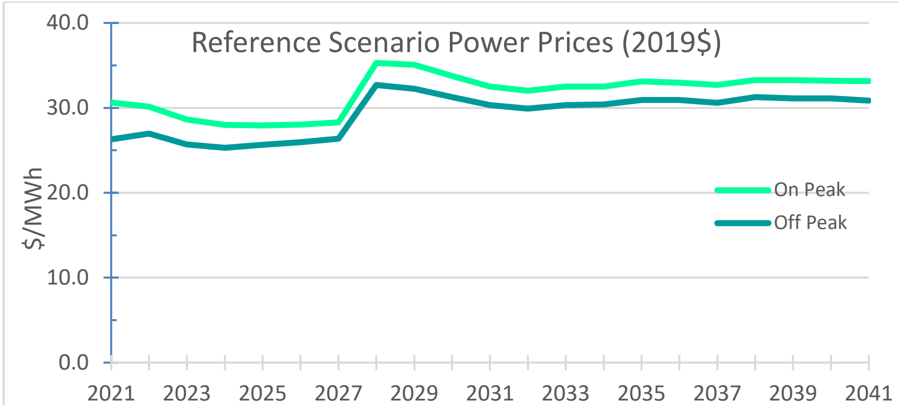

Figure 27. AEP I&M Zone Reference Scenario Power Prices (2019$/MWh)

7.5 Avoided Costs

7.5.1 Avoided Capacity Costs

For this IRP, the avoided capacity costs are taken from the Company's fundamentals forecast as the proxy estimate for the marginal market cost for capacity on the PJM market. The avoided generation capacity cost utilized in this analysis is shown in Figure 27. For the Reference and RTA scenarios as defined in Section 7.4, the base fundamental capacity cost was used. For the Enhanced Regulation scenario, the High CO_2 capacity cost was used.

7.5.2 Avoided Transmission and Distribution Cost

The Company's transmission and distribution systems are designed, constructed, and operated to serve not only the load physically connected to I&M's wires, but also to operate adequately and reliably with interconnected systems. The T&D systems must have the capacity to link generation resources safely and reliably with various load centers while also interfacing with, and managing, the loads from distributed resources as well, whether owned by the Company or by other entities including end use customers. For this IRP, a system level estimate of $20 per kW-year was applied to demand-side resource costs within the MPS to augment the program benefit stream. This system level estimate represents the Company's valuation for any localized benefits that may be realized from T&D system capital deferrals (i.e. avoided costs) resulting from EE, DR, and DER and is consistent with the avoided T&D costs used in the I&M AMI Business Case (I&M AMI CBA) performed by Accenture in 2020. In the I&M AMI CBA, the Company and Accenture performed analysis to determine the $20 per kW-year level for avoided T&D to be within industry range and appropriate to I&M specific.

7.5.3 Avoided Energy & Operating Cost

I&M's avoided operating cost including fuel, plant Operation & Maintenance (O&M), spinning reserve, and emission allowances, excluding transmission and distribution losses as discussed above, is provided in Figure 27.

7.6 Supply-Side Resource Options and Costs

7.6.1 Overview

New supply-side capacity alternatives were modeled to represent peaking and baseload/ intermediate capacity resource options. Natural gas base/intermediate, peaking generating technologies, large-scale solar and wind resources, hybrid energy resources and stand-alone storage resources were all considered as part of this IRP.

For this IRP, the cost and performance characteristics of the resources were informed through a combination of the EIA Annual Energy Outlook,[15] the NREL Annual Technology Baseline Report,[16] and with All-Source Informational RFP / Renewable RFP Results. The EIA AEO Report provided the basis for most conventional resources, while renewable and storage resources were informed by the All-Source Informational RFP and the Siemens PTI National Model. The NREL AEO report provides long-term forecasts for technologies and is the source of the learning curve applied to annual capital costs.

The IRP modeling considered generic resource cost and performance characteristics and did not attempt to model resource differences based on ownership structure for example (owned, power purchase agreement, tax equity, etc.). This approach allows the IRP modeling and process to focus on resource type and the underlying performance and installed and operating cost that are common regardless of ownership structure. This also avoids potentially inaccurate treatment when modeling federal and state policies and other ownership structure characteristics that are examined in more detail when specific resources are being acquired. Furthermore, as discussed in the Short-Term Action Plan the Company has committed to using an all-source RFP to solicit resources needed in the Near-Term. This will ensure the timely recognition of federal tax policies and allows for the consideration of project specific accurate and relevant information needed to evaluate the best resources for I&M. This includes the consideration of items such as: tax efficiency and utilization, terminal value of owned projects, impacts to financing costs and availability of financing, etc.

To improve the robustness of model results, a number of alternative resources explicitly modeled were reduced through an economic screening process focused on observed penetration in AURORA LTCE runs. The Siemens PTI team identified a set of forecasted expensive resources that the LTCE process routinely did not select as a reasonable option. Specifically, Coal and Coal with Carbon Capture Utilization and Storage (CCUS) base-load options were considered but were ultimately removed from the AURORA resource optimization modeling analyses. For coal generation resources, environmental regulation (see Section 6) makes the construction of new coal plants economically impractical. It is important to note that alternative technologies with comparable cost

[15] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

[16] https://atb.nrel.gov/

and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant.

Table 7 and Table 8 below offer a summary of the technology performance parameter data. Appendix Volume 1, Exhibit D includes a summary of these performance parameters and resource costs:

Table 7. Plant Performance and Financial Data, Fossil

Plant Parameters	Fossil			
Technology	Advanced 1x1 Combined Cycle w 90% CO_2	Advanced 2x1 Combined Cycle	Advanced 1x1 Combined Cycle	Simple Cycle Frame CT
Fuel	Nat.Gas	Nat. Gas.	Nat. Gas	Nat. Gas.
Development Time (yrs)	7	6	5	5
Size (MW)	390	1,070	440	250
Baseload Heat Rate, HHV (Btu/kWh)	6,431	6,370	6,431	9,905
VOM (2019$/MWh)	5.84	1.87	2.55	0.60
FOM (2019$/kW-yr)	27.59	11.26	14.10	7.00
Book Life	30	30	30	30
Debt Life	30	30	30	30
Pre-Tax WACC	7.19%	7.19%	7.19%	7.19%

Table 8. Plant Performance and Financial Data, Carbon Free

Plant Parameters	Storage	Nuclear	Renewables			
Technology	Batteries - Li-ion	Small Modular Reactor	Solar Tier-2	Solar + Storage	Solar Tier-1	Onshore Wind
Fuel	All	Uranium	Sun	Sun	Sun	Wind
Development Time (yrs)	1	10	1	1	1	1
Size (MW)	50MW/ 200MWh	600	50	100	50	200
Baseload Heat Rate, HHV (Btu/kWh)		10,046				
VOM (2019$/MWh)		3.03				PTC
FOM (2019$/kW-yr)	20.67	96.14	16.70	37.55	16.70	31.72
Book Life	30	40	35	10	35	30
Debt Life	10	40	35	10	35	30
Pre-Tax WACC	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%

7.6.2 Base/Intermediate Alternatives

7.6.2.1 Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a Heat Recovery Steam Generator (HRSG) to produce steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-63% Lower Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 10 to 12 years, NGCC plants were often selected to meet new intermediate and certain base-load needs. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach reduces efficiency at full-load but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a HRSG that will give the widest load range with minimum efficiency penalty.

At this time, the Company considers both "1x1" (one combustion turbine generator and one steam turbine generator) and "2x1" (two combustion turbine generators and one steam turbine generator) combined cycle configurations to be the best fit as they most align with historical operating experience and expected output relative to the overall Company's needs.

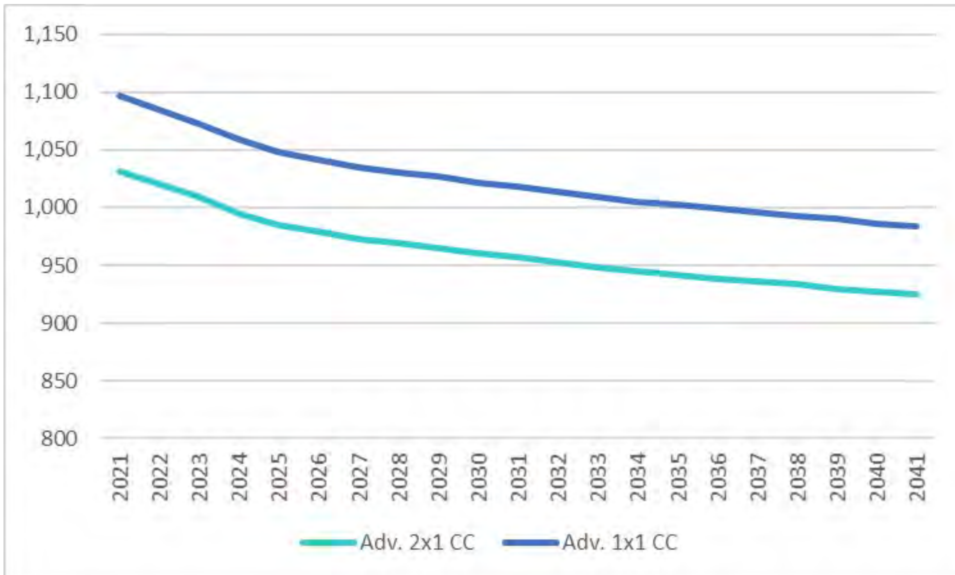

Figure 28. CC 2x1 and 1x1 All-in Capex (2019$/kw)

It's important to note that the NGCC technology discussed above can in fact operate on several different fuels with minor modifications to the CT combustion hardware and software. For more than ten years, major CT manufacturers refined the combustion characteristics of their respective offerings to effectively combust a wide array of industrial gas and synthetic fuels – including hydrogen. So called "green" hydrogen[17] produced from electrolysis of water using renewable power, is rapidly moving past the pilot phase as a power generation fuel worldwide. Depending upon the exact CT model, CTs are currently capable of reliably firing hydrogen/natural gas fuels blends ranging from 30% hydrogen, potentially increasing to 100% hydrogen, and several projects are underway across the U.S. which will soon use hydrogen fuel.

7.6.2.2 Small Modular Reactor (SMR)

While no small modular reactors are currently operating, several are under consideration nationwide. A few manufacturers are conducting research, developing designs, and working to gain Nuclear Regulatory Commission (NRC) approval. SMRs operate essentially the same as conventional nuclear reactors in that nuclear fuel is used to generate heat which in turn is used to produce steam at pressure that is expanded through a steam turbine generator to produce electricity. SMRs differ from traditional nuclear reactors in a few keyways. First, SMRs designs are inherently safe, so that in event of an emergency where cooling pumps cannot be operated, the unit goes into a fail-safe mode. Second, as the name suggests, the design is modular, permitting developers to select the number of modules needed to meet a specific power requirement. Each module is generally between 50 and 72 MWs, depending upon the manufacturer. Third, each module will be constructed in a

17 Green hydrogen is made with electrolyzers powered by non-carbon emitting resources. Other types of hydrogen production, for example "blue" hydrogen, are made from reforming methane with CCS of the CO_2 byproduct.

factory setting to improve quality control thereby minimizing field modifications, which have historically resulted in significant cost overruns.

7.6.2.3 Carbon Capture Utilization and Storage (CCUS)

To reduce the carbon emissions of fossil combusting technologies, carbon capture technology has been applied on a limited basis globally. This technology captures about 90% of the carbon emissions from a coal or gas-fired industrial or power generating plant which may then be used for an industrial purpose like enhanced oil recovery, fuel production, etc., or directly stored deep underground. At present, twenty-six commercial-scale carbon capture projects are operating globally with 21 more in early development and 13 in advanced development.

7.6.3 Peaking Alternatives

Peaking generating sources provide needed capacity during high-demand periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for “quick-response” capability. The peaks occur for only a small number of hours each year and the installed reserve requirement is predicated on a one day in ten-year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide relatively little energy over an annual load cycle. As a result, fuel efficiency and other variable costs applicable to these resources are of lesser concern. Rather, this capacity should be obtained at the lowest practical installed/fixed cost, despite the fact that such capacity often has very high energy costs and produce reliably when called upon. Ultimately, such “peaking” resource requirements are manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency, Black Start, capability to the grid.

7.6.3.1 Simple Cycle Natural Gas Combustion Turbines (NGCT)

In “industrial” or “frame-type” Combustion Turbine (CT) systems, air compressed by an axial compressor is mixed with fuel and burned in a combustion chamber. The resulting hot gas then expands and cools while passing through a turbine. The rotating rear turbine not only runs the axial compressor in the front section, but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800- and 1,150-degrees Fahrenheit and contains substantial thermal energy. A CT system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, *i.e.,* not recovered as in a combined-cycle design. While not as efficient (at 30-35% Lower Heating Value), they are inexpensive to purchase, compact, reliable, and simple to operate. Additionally, as discussed above with the NGCC resources, the NGCT resources operate on several different fuels with minor modifications.

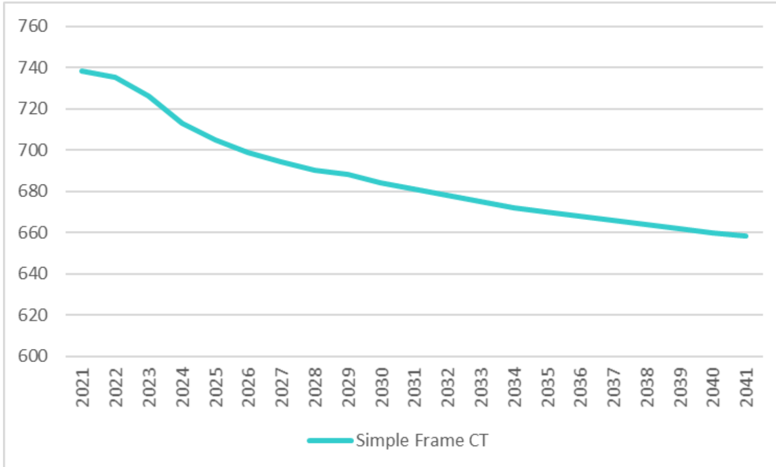

Figure 29. NGCT All-in Capex (2019$/kw)

7.6.3.2 Battery Storage

The modeling of Battery Storage as a Peaking resource option is becoming a more common occurrence in IRPs. In recent years Lithium-ion battery technology has emerged as the fastest growing least cost platform for stationary storage applications. The Battery Storage resource that was modeled in this IRP is a Lithium-ion storage technology and it has a nameplate rating of 50MW and 200MWh. Figure 30 below shows the forecasted all-in capital cost of this resource. See Section 7.6.4.3 below for a discussion of the hybrid resources included in this IRP.

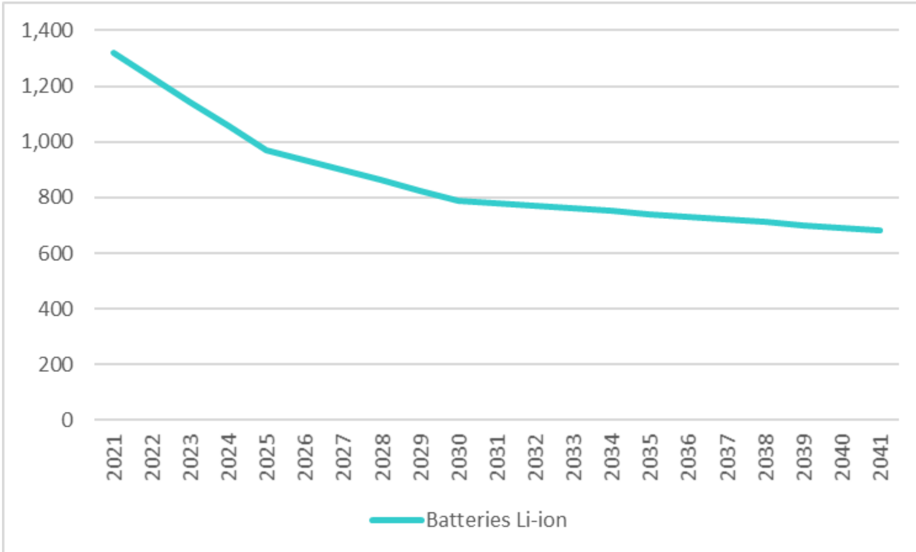

Figure 30. Battery Storage All-in Capex (2019$/kw)

7.6.4 Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). Until recently, development of renewable resources was largely driven primarily by resource availability, renewable portfolio standards, and supporting tax policies. These drivers remain in place today, which when coupled with reduced costs and increased technology capacity factors, makes renewable technologies highly competitive with traditional fossil resources on a cost of energy basis. Within the IRP, modeling of federal tax credits associated with renewable investments assumed efficient tax realization of these benefits as described further in sections 7.6.4.1 and 7.6.4.2.

7.6.4.1 Utility-Scale Solar

Energy from the sun can be used to generate electricity by using either concentrated solar or photovoltaic technology. Concentrating solar focuses the sun's rays to heat a working fluid to temperatures sufficient to generate steam. This steam is injected into a conventional steam turbine generator to produce electricity and is similar to traditional centralized supply assets in that stage. Photovoltaics can more easily be distributed throughout the grid and are a scalable resource that, for example, can be as small as a few kilowatts or as large as 500MW. This IRP considers photovoltaic technology.

The cost of utility-scale, solar projects has declined in recent years and is expected to continue to decline. This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy globally. With the trend firmly established, forecasts generally foresee declining nominal prices and improved performance in the next decade as well, notwithstanding solar panel tariffs which from an IRP perspective are regarded as a short-term impact.

Solar resources were made available in the AURORA model with some limits on the rate with which they could be chosen. In the IRP modeling, large-scale solar resources were available in yearly quantities up to 500MW of nameplate capacity starting in 2025. A limit on solar capacity additions is needed because as solar costs continue to decrease relative to the market price of energy, there will come a point where the optimization model will theoretically pick an unlimited number of solar resources, a nonsensical result. Solar resources were available in two tiers with up to 250 MW per tier. Tier 2 as referred to in this IRP, is the average of higher bids received as part of the All Source and Renewable RFP. Tier 1 pricing is considered a “Best-In-Class” solar resource and is based on the lowest bid received for solar resources from the All Source and Renewable RFP. Both tiers of solar resources were available in blocks of 50MW. Additionally, both tiers of solar resources were modeled with capacity factors of approximately 22.4%, which is representative of a single axis tracking solar resource located in Ft. Wayne, Indiana.

Figure 31 below illustrates the projected large-scale solar pricing included in the IRP model. Both tiers account for Federal ITCs. The large-scale solar pricing used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has commenced. The ITC benefit of 26% is included through 2025 and then declines to 10% throughout the remainder of the forecast horizon.

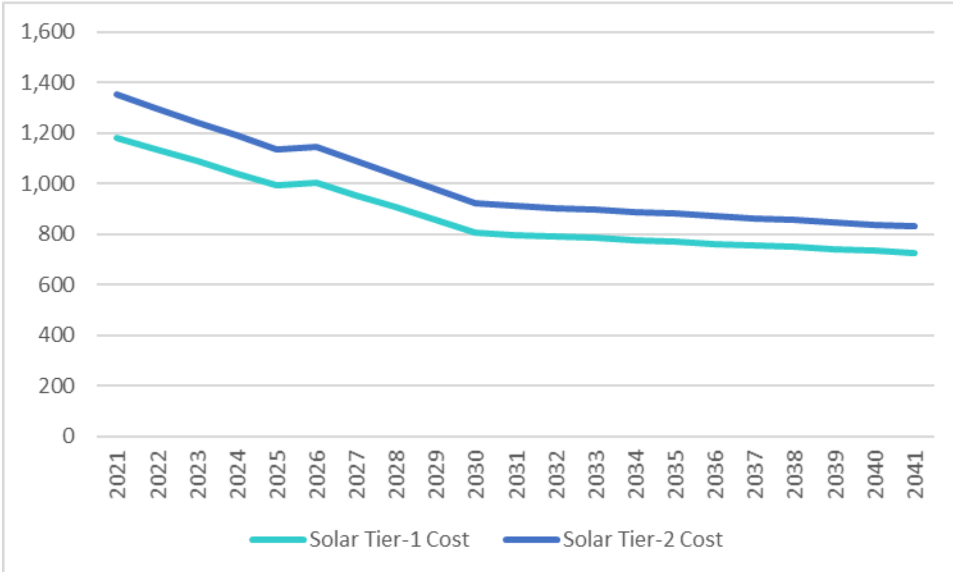

Figure 31. Solar Tier 1 and Tier 2 All-in Capex (2019$/kw)

7.6.4.2 Wind

Utility-scale onshore wind energy is generated by projects usually containing many turbines ranging from 1.0 to 3.2MW each. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Careful site selection and turbine placement within the project are particularly critical since wind velocity varies by geography, and the proximity of the wind farm to a transmission system with available capacity, which impacts cost.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 percent (in the eastern portion of the U.S.) to over 50 percent (largely in more westerly portions of the U.S., including the Plains states), and has negligible operating costs.

Another consideration with wind power is that its most critical factors (*i.e.*, wind speed and sustainability) are typically highest in more remote locations, which can require the electricity to be transmitted longer distances to load centers necessitating the build out of high voltage transmission to optimally integrate large additions of wind into the grid.

For modeling purposes, wind resources are first made available to the model in 2025 (i.e., commercial operation date 12/31/24), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals. The figure below shows the All-in CapEx costs for wind resources. Wind resources were modeled as a 200MW resource with a 40.5% capacity factor load shape. Wind resources capacity credit for capacity planning purposes is based on PJM's ELCC analysis and is assumed to start at 15% and reduce to 11% by 2028 of nameplate.[18] The wind pricing reflects the value of Federal Production Tax Credits (PTCs). For this IRP, the Company assumed 60% PTC for projects in service by the end of year 2025. These PTC values are based on developers taking advantage of the safe-harbor guidelines which provide up to a four-year delay in the effects of declining tax credits as long as adequate construction has commenced. Wind costs were developed based on the Siemens National Forecast Model.

The amount of wind resources available beginning in 2025 was limited to 800 MW nameplate annually through the remainder of the planning period. In total, wind resources were limited to 1,600 MW nameplate over the planning period until 2034, and then increased to 3,200 MW through the remainder of the planning period. The annual limit on wind additions is based on the two RFPs that were considered for this IRP and I&M's ability to plan, manage, and develop either the construction or the procurement of these resources.

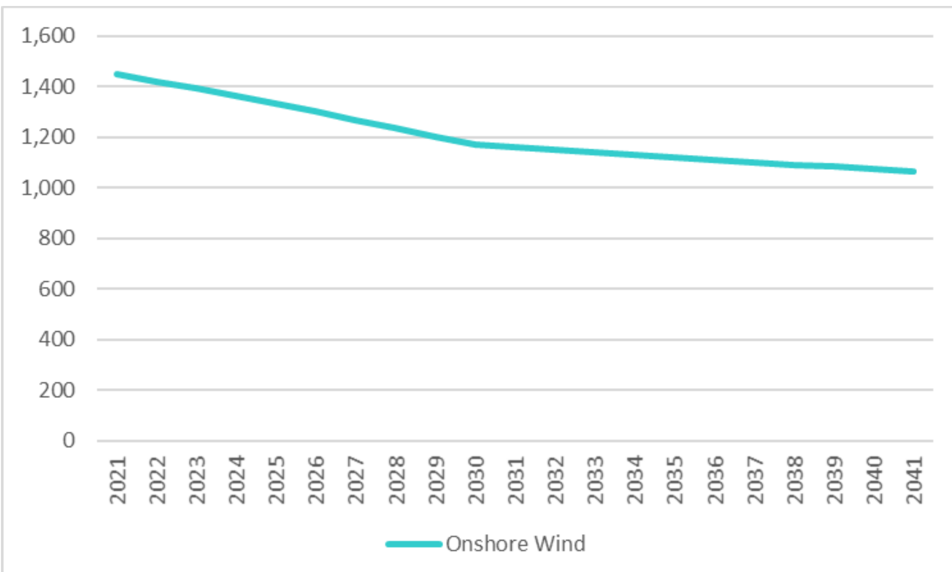

Figure 32. Wind Resources All-in Capex (2019$/kw)

7.6.4.3 Hybrid Resource Options

Hybrid renewable energy systems combine a renewable energy source and/or energy storage technologies into a single plant. The value behind a hybrid resource is the ability to charge the storage with low-cost renewable energy which would be available to discharge during high demand hours where there is, theoretically, limited renewable or low-cost energy available to meet the necessary load requirements.

[18] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx).

As modeled in this IRP, the ELCC for the solar and storage components were calculated individually based off the ELCC curves for their specific technologies described in Section 7.6.4.4. The capacity ratio for a single hybrid resource available is a 100/20 MW Solar/Storage ratio with a 4-hour charging period for a maximum charge of 80MWh.

For modeling purposes, hybrid resources were assumed available for 2025 (i.e., commercial operation date 12/31/24), due to the amount of time necessary to secure resources and obtain any necessary regulatory approvals.

Figure 33 below illustrates the projected Solar + Storage All-In capital cost included in the IRP model. Solar + Storage short-term market costs decline rapidly in the initial years in line with the learning curves derived from the NREL ATB report. The hybrid solar + storage cost used in this IRP reflects a normalized treatment of the ITC, as well as a four-year safe harbor factor in ITC pricing. This safe harbor factor allows projects to lock in ITC benefits four years prior to commercial operation, as long as construction has commenced. The ITC benefit is included through the forecast horizon.

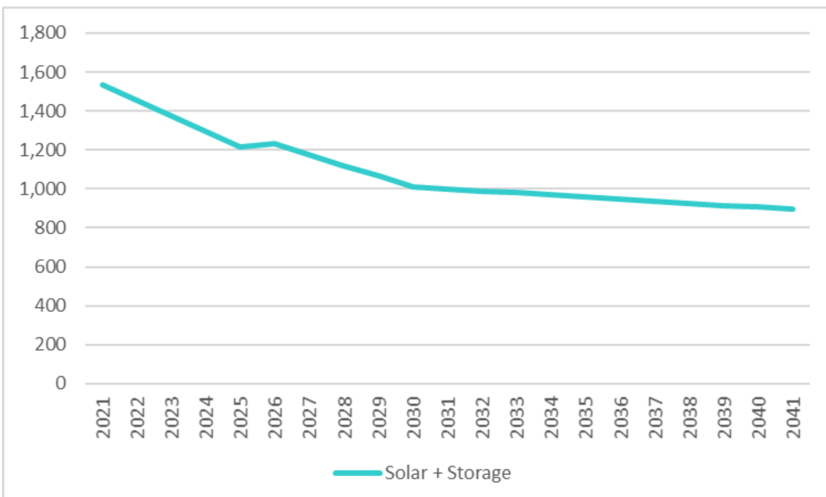

Figure 33. Hybrid Solar + Storage All-in Capex (2019$/kw)

7.6.4.4 Effective Load Carrying Capability (ELCC)

Effective Load Carrying Capability (ELCC)[19] is a method to quantify the resource adequacy contribution of a resource. For this IRP, PJM's guidance for ELCC of renewable and intermittent resources were modeled. Figure 34 below illustrates the ELCC applied to resources available in the modeling.

[19] https://www.pjm.com/-/media/planning/res-adeq/elcc/elcc-class-ratings-for-2023-2024-bra.ashx

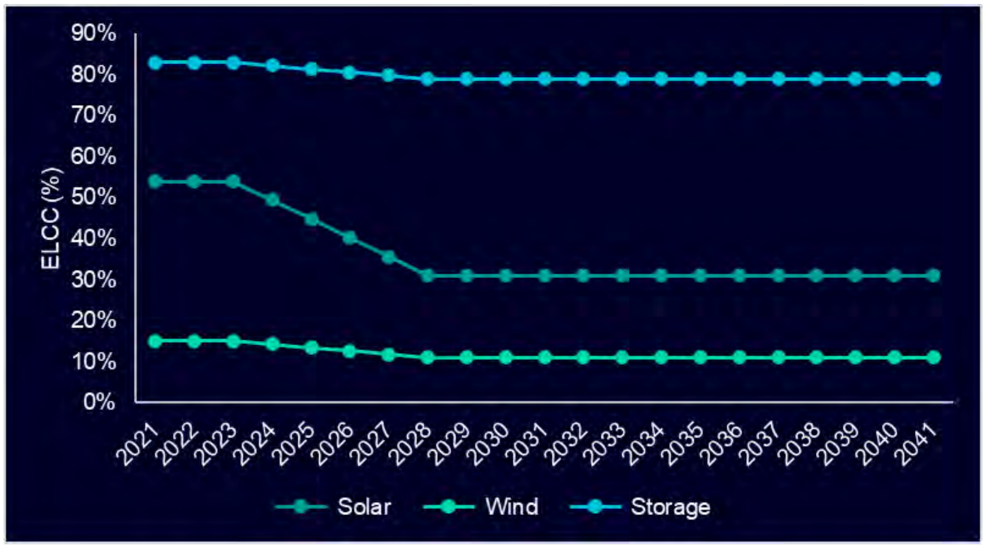

Figure 34. Effective Load Carrying Capability

7.6.5 Additional Modeling Considerations

7.6.5.1 Resource Limits

Additional modeling parameters were included to account for various logistical, commercial, and operational limitations that arise from procuring and deploying new resources. These limits, as shown in Table 9 below, reflect reasonable and practical annual and cumulative resource additions to help manage energy export value, regulatory approval, annual customer rate impact and project implementation risk. Furthermore, renewable and hybrid resource limits were informed by responses received from the Company's RFP's. In developing the Table 9 parameters, the Company considered when future resources could be needed associated with the timing of resource needs.

Table 9. Modeled Resource Parameters

Resource Limits (MW)	Annual	Cumulative		
	2025+	2025-2034	2035-3037	2038+
Solar Tier 1	250	1,800	2,400	3,500
Solar Tier 2	250	1,800	2,400	3,500
Solar Hybrid	500	1,800	2,400	3,500
Wind	800	1,600	3,200	5,800
Gas CC 2x1	1,070	1,070	1,070	1,070
Gas CC 1x1	440	880	880	880

Gas CT Adv.	500	4,000	4,000	4,000
SMR	600	1,200	1,200	1,200

7.6.5.2 Resource Capital Costs for the Rapid Technology Advancement Scenario

For the RTA Scenario, advanced technology resources costs were reduced by 35% shown in Figure 35.

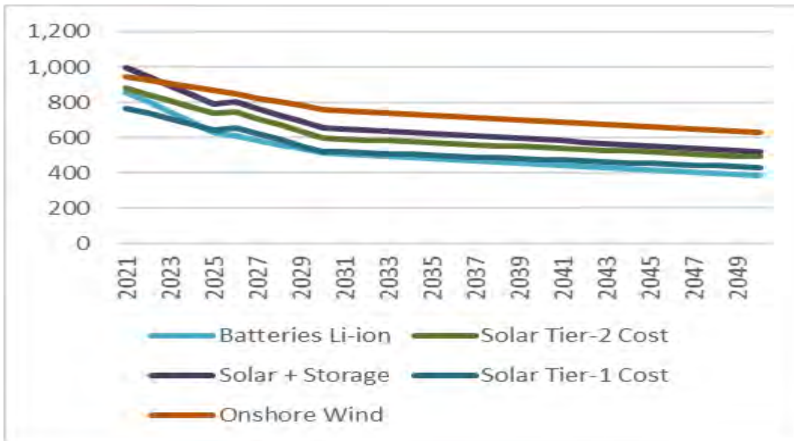

Figure 35. All-in CapEx (2019$/kW), Rapid Technology Advancement Scenario

7.7 New Demand-Side Resources

As part of the IRP, additional or "incremental" demand-side resources beyond those described in Section 5.6.2 were identified and ultimately modeled based on I&M's 2021 MPS performed by GDS Associates and Brightline Group ("the GDS Team"). Non-income qualified EE programs were modeled on a comparable economic basis as supply-side programs while all other Demand-side programs were informed by the MPS and included in the IRP.

7.7.1 DSM Market Potential Study Overview

To evaluate the potential for future DSM resources in the 2021 I&M IRP, I&M utilized the MPS prepared by the GDS Team for energy efficiency, demand response, and distributed energy resources potential. The I&M MPS provided updated DSM programs, measures, costs and energy and demand savings for a 20-year time horizon (2023-2042). The study included primary market research and a comprehensive review of current programs, historical savings, and projected energy savings opportunities, to develop estimates of technical, economic, and achievable potential. Separate estimates of energy efficiency, demand response, and distributed energy resources (DER) potential were developed. EECO or CVR was not evaluated in the MPS as I&M had previously conducted an analysis for energy and demand savings across all circuits in the I&M service area.

7.7.2 Modeling Framework

The GDS Team used its Excel-based energy efficiency and DR planning models to perform all of the analyses in the I&M MPS. These models allow the user to develop forecasts of measure and program costs, participants, kWh and kW savings, and benefit/cost ratios over the planning horizon. These models are transparent and all formulas, model inputs and model outputs can be viewed by the model user.

7.7.3 MPS Adjustment to I&M's Energy Sales Forecast

Before assessing the future potential for energy efficiency, demand response, or distributed energy resources in the I&M service area, a few modifications to I&M's 2020-vintage forecast were necessary to create an adjusted baseline forecast for use in the MPS.

First, the I&M sales forecast uses the appliance efficiency forecast published in the EIA Annual Energy Outlook (AEO) as inputs for the various end-use indices contained within the statistically adjusted end-use models employed by I&M. Over time, the EIA appliance efficiency projections allow for existing equipment stock to exceed the prevailing federal minimum efficiency standards. In contrast, the majority of savings from efficient technologies in the MPS (and included in the recommended I&M DSM programs) are based on comparisons to equipment that meets, but does not exceed, known federal minimum efficiency standards. To align the sales forecast used in the MPS with the assumed savings opportunities, the GDS Team developed an adjusted "code frozen" forecast that permits the existing equipment stock to improve and meet, but not exceed, legislated federal minimum standards. The result is a sales forecast that is higher, over the 20-year horizon, than I&M's base sales forecast associated with the IRP.

Second, in Indiana, commercial or industrial customers with a peak load greater than 1MW are eligible to opt out of utility-funded electric energy efficiency programs. In the I&M service area, approximately 9% of commercial kWh sales have opted out of utility-funded electric energy efficiency programs, while roughly 50% of industrial kWh sales have opted out. GDS excluded these sales from the forecast and associated estimates of future electric energy efficiency potential.[20]

Last, commercial, and industrial (C&I) sales in the I&M forecast are consistent with the designated commercial and industrial rate code based on the current tariff designation. As a result, there were a small number of customers that the GDS Team typically classifies as commercial, based on their Standard Industry Code (SIC), designated as industrial in the 2019 I&M C&I sector customer databases. To better align commercial vs. industrial savings opportunities with a facilities typical service area, the GDS team reclassified these industrial sales to the commercial sector. The result

[20] As a sensitivity in the Market Potential Study, GDS produced an estimate of potential savings assuming commercial and industrial customers could no longer opt-out of utility-funded electric energy efficiency programs. The I&M IRP and associated DSM inputs reflect the current conditions that allow opt-out customers in Indiana.

of this reclassification was a shift of approximately 0.5% of industrial sector sales in Indiana, and 0.3% of industrial sector sales in Michigan, to the commercial sector.

7.7.4 Energy Efficiency (EE) Measures & Potential

7.7.4.1 Measures Considered

Measure list development during the I&M MPS was a collaborative effort in which the GDS Team developed draft lists that were shared with I&M and MPS Stakeholders. The energy efficiency measure lists were informed by a wide range of sources, including current I&M program offerings, the Michigan Energy Measures Database (MEMD), the Illinois Technical Reference Manual (TRM), and commercially viable emerging technologies, among others. The final measure lists ultimately included in the study reflected the source review and considerations from the parties that participated in the measure list review process.

In total, the GDS Team analyzed 353 unique EE measure types for this study. Several measures were included with multiple permutations to account for specific market segments, such as different building types, efficiency levels, and replacement options. In total, GDS developed 2,106 measure permutations each for I&M's Indiana and Michigan service areas.

Table 10. Number of Electric Measures Evaluated in Market Potential Study

	Number of Measures	Total Number of Measure Permutations
I&M		
Residential	168	673
Commercial	157	1,405
Industrial/Ag[21]	28	28
Total	353	2,106

Within the residential, commercial, and industrial market segments, the energy efficiency measures targeted the following major end-uses:

[21] For the industrial sector, the analysis employed a top-down analysis at the end-use level as opposed to a detailed measure analysis. The GDS Team selected this approach to more comprehensively target industrial loads given the myriad of different energy-consuming equipment within industrial facilities and to align with the methodological approach employed by the Michigan Public Service Commission's independent statewide analysis of future market potential.

Table 11. Electric End-Uses Included in the Market Potential Study

Residential	CC&I	
	Commercial	Industrial
Heating	Interior Lighting	Lighting
Cooling	Exterior Lighting	HVACHVAC
Water Heating	Refrigeration	Machine Drive
Cooking	Space Cooling	Process Heat
Refrigerator	Space Heating	Process Cool / Refrigeration
Freezer	Ventilation	Other Process
Dishwasher	Water Heating	Process – Machine Drive
Clothes Washer	Plug Loads / Office Equipment	Other Facility
Dryer	Cooking	Compressed Air
TV	Other	Water / Wastewater
Light	Whole Building / Behavioral	Process – Agriculture
Miscellaneous		Whole Building / Behavior

7.7.4.2 I&M DSM Measure Assumptions and Market/Equipment Characteristics

The GDS Team reviewed the assumptions for measure costs, savings and useful lives included in prior I&M DSM plans and updated these assumptions where appropriate. The GDS Team utilized data specific to I&M when it was available and current. I&M evaluation report findings, I&M program planning assumptions, and the MEMD were leveraged to the extent feasible – additional data sources were only used if these sources either did not address a certain measure or contained outdated information. Additional source documents included the Illinois Technical Reference Manual (TRM), Energy Information administration (EIA), American Council for an Energy-Efficient Economy (ACEEE) research reports, the Northwest Power Conservation Council and Regional Technical Forum (Industrial processes), and DOE commercial building reports.

In addition to measure assumption development, the GDS Team engaged in primary market research to collect updated equipment penetration, saturation, and efficiency characteristics, as well as customer willingness to participate in program offerings data, across select end-uses/technologies. Due to COVID-19 considerations and overall schedule constraints, the GDS Team conducted a web-based survey to complete the research. The resulting data was used to develop updated estimates of baseline and efficient equipment saturation estimates in the market potential study and to develop expected long-term adoption rates for energy efficiency over the study horizon.

7.7.4.3 Electric Energy Efficiency Potential

The amount of available EE is typically described in four sets: technical potential, economic potential, achievable potential, and program potential.

Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, whether or not it is cost-effective (i.e., all EE measures would be adopted if technically feasible). The logical subset of this pool is the economic potential. In both the Indiana and Michigan jurisdictions, economic potential for energy efficiency only includes measures that are cost-effective based on screening with the Utility Cost Test (UCT). In I&M's service territory, the UCT considers electric energy, capacity, and transmission & distribution (T&D) savings as benefits, and utility incentives and direct install equipment expenses as the cost. Consistent with application of economic potential according to the National Action Plan for Energy Efficiency, the measure level economic screening does not consider non-incentive/measure delivery costs (e.g., admin, marketing, evaluation etc.) in determining cost-effectiveness.[22]

Except for the low-income segment of the residential sector, all measures were required to have a UCT benefit-cost ratio greater than 1.0 to be included in economic potential and all subsequent estimates of energy efficiency potential. Low-income measures were not required to be cost-effective.

Achievable potential is the amount of cost-effective energy that can realistically be saved given various market barriers. Achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis, and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial constraints, customer awareness and willingness-to-participate (WTP) in programs, technical constraints, and other barriers that the "program intervention" is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- Maximum Achievable Potential (MAP) estimates achievable potential with I&M paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- Realistic Achievable Potential (RAP) estimates achievable potential with I&M paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

Finally, the GDS Team conducted research and analysis to identify areas for I&M to consider for potential improvements to the current program portfolio. Program potential also considers what can or should be accomplished with utility-sponsored programs versus energy efficiency savings that happen through alternative interventions. Overall, the GDS Team refined the Realistic Achievable Potential into the Program Potential scenario based on the following updated factors:

- Incentive levels and structures: Measures within existing I&M programs were modeled within their current framework unless research dictates otherwise

[22] National Action Plan for Energy Efficiency: Understanding Cost-Effectiveness of Energy Efficiency Programs. Note: Non-incentive delivery costs are included in the assessment of program potential and overall DSM budgets for IRP inputs.

- Program non-incentive costs (admin)
- Measure Assignments: In some cases, achievable potential cost-effective measures were reassigned to new program types

A comparison of the Realistic Achievable Potential (RAP) and Program Potential is shown below. The decrease from RAP to Program Potential in the residential sector is driven by changes in program mapping for certain measures, aligning the income-qualified program spending with historical levels to reduce cross subsidization concerns across customer segments, as well as programs being dropped from the program potential if not cost-effective at the program-level (i.e., after including administrative costs).

Table 12. Comparison of MPS Achievable and Program Potential (20-YR Cumulative Annual MWH)

Program	RAP (gross)	Program Potential (gross)
Residential	837,529	464,715
C&I	1,175,228	1,181,177
Total	2,012,756	1,645,891

7.7.5 Demand Response (DR) Potential

Demand response (DR) potential for the I&M territory was estimated following a similar methodology as the EE analysis. Technical, economic, and two achievable scenarios (maximum and realistic) were developed for I&M's territories considering the potential for 23 different DR program iterations. Expansions to I&M's existing DR programs were considered, as well as new program opportunities. Utility cost components included program development, implementation, incentive, and evaluation costs. Programs were screened using the UCT, using a threshold of 1.0 and considering the performance of the program across the full twenty-year study period. In this study, the MAP scenario represents a 'best practice' estimate of what could be achieved considering I&M's customers' likely participation rates and assumes higher levels of incentives for participation. The RAP scenario reflects a realistic scenario estimate based on typical or 'average' participation rates likely to be achieved considering program barriers. Program types that compose the MAP and RAP scenarios are listed in Table 13.

Table 13. DR Potential Study Program Results by Sector

Sector	Program	MAP	RAP
Residential	Connected Thermostat	XX	X
	Time-of-use (TOU) Rate w/o enabling technology	X	X
	Critical Peak Pricing (CPP) Rate w/o enabling technology	X	X
	Central AC DLC	X	X
	Behavioral	X	X
C&I	Connected Thermostat	XX	X
	DWHDWH DLC	XX	X
	Real Time Pricing (RTP) Rate	X	X
	Critical Peak Pricing (CPP) Rate w/o enabling technology	X	X
	Time-of-use (TOU) Rate w/o enabling technology	X	X
	Capacity Bidding	X	X
	Curtailable Rate	X	

The RAP results for demand response by sector over the MPS horizon are shown in Figure 36 for Indiana and Figure 37 for Michigan respectively.

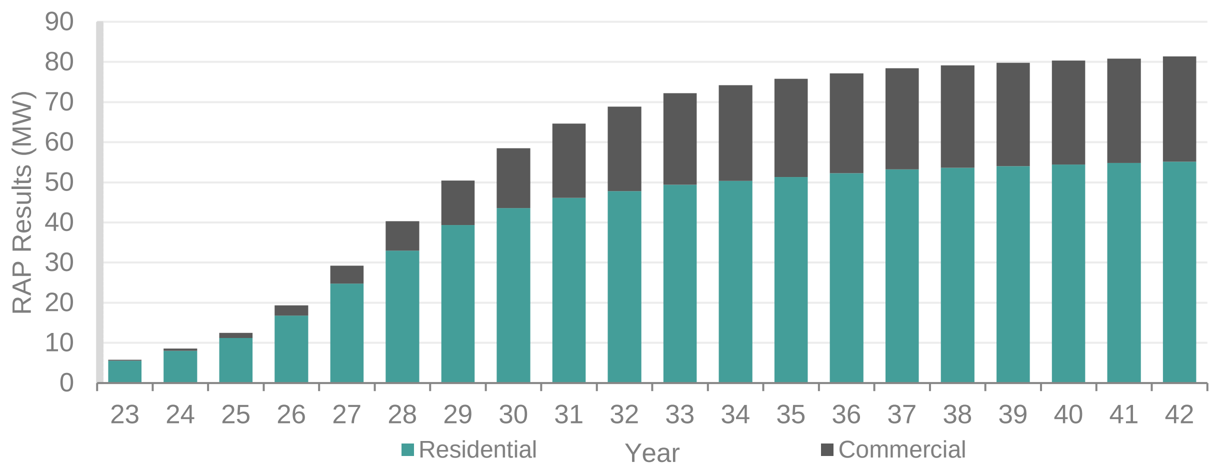

Figure 36. Realistic Achievable Demand Response Potential by Sector – Indiana

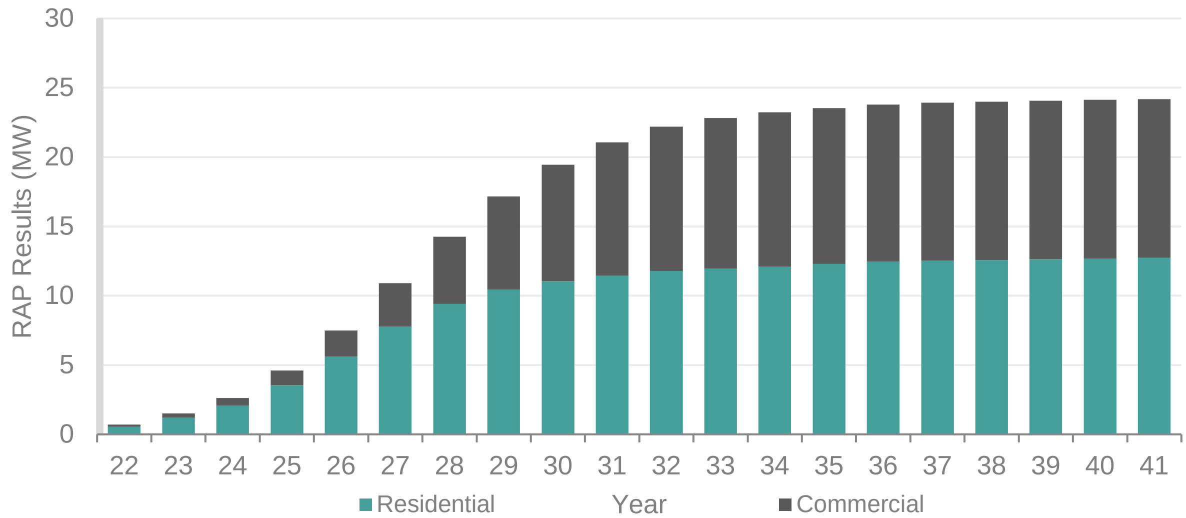

Figure 37. Realistic Achievable Demand Response Potential by Sector - Michigan

7.7.6 Distributed Energy Resources (DER) Potential

DER resources were modeled based on residential and non-residential solar photovoltaic (PV) and non-residential combined heat and power (CHP) resources. Potential for both resources was assessed based on premise-level availability to host the DER technology across I&M's territory with economic analysis based on estimated market costs and generation benefits to the end-use customer. To determine the level of customer penetration, I&M estimated adoption forecasts based on Bass diffusion curves. The diffusion curves were informed by existing installed systems, assumed maximum market penetration, and coefficients of innovation and imitation. GDS used I&M's internal customer data to inform quantities of existing solar PV and CHP systems active in I&M's service territory. Using primary research conducted in 2021 with I&M residential and non-residential customers, GDS estimated various adoption levels to calculate scenarios of maximum market penetration. The Bass curve was fitted within these parameters using innovation and imitation coefficients based on state-specific research conducted by NREL.[23] This forecast considered the level of solar (PV) and CHP installations over the 20-year MPS time horizon.

The DER analysis ultimately found all modeled solar PV and CHP resources were not cost effective according to the Total Resource Cost (TRC) Test. The TRC Test was selected as the primary cost-effectiveness screening test for DERs to encapsulate both utility and customer perspectives and

[23] Sigrin, B, *et. al*. The Distributed Generation Market Demand Model (dGen): Documentation. National Renewable Energy Laboratory. February 2016.

determine whether a utility-sponsored program intervention is prudent. Ultimately, no solar PV or CHP technologies passed cost-effectiveness screening under the TRC.[24] As a result, achievable market potential was not assessed.

While the analysis shows that DER is not cost effective from the customer perspective, the Company did include in the IRP modeling an assumed level of incremental DER.

7.8 Future DSM Resources

7.8.1 Energy Efficiency Bundles

7.8.1.1 Bundle Development

EE bundles for modeling were developed by the GDS Team used a statistical process, known as "k-means clustering", to determine the number of bundles and which measures to assign to individual bundles.

In statistical terms, k-means clustering measures the Euclidean distance between a randomly selected "centroid" (a single point in the Euclidean space), and a single data point, which in this analysis is an EE measure. A set number of bundles is defined for the process to assign each EE measure to one of the bundles. The process is iterative for each EE measure until the distances between points are minimized.

The NPV benefits and costs per lifetime kWh savings for each EE measure were used to cluster the measures into bundles. After the k-means clustering analysis is performed and each measure has been assigned to a bundle, various statistical metrics are output to help the user determine the quality of the clustering for that set number of bundles. The clustering analysis was performed for numbers of bundles ranging from two to twenty. There is no right or wrong answer when selecting the number of bundles, as the user must weigh the feasibility of using any number of bundles against the statistical metrics that help to identify the better numbers of bundles.

Based on the k-means clustering outputs, the GDS Team identified five residential bundles, one income-qualified bundle, and eight C&I bundles for IRP inputs. Based on measure-bundle assignment, the GDS Team then mapped the program potential savings from the Market Potential Study into the identified EE bundles for IRP model input. It is important to note that the bundles are not equal in measure counts or overall magnitude of savings. Select bundles are as small as a single measure type, while other bundles represent a comprehensive suite of measures across various

[24] The GDS Team conducted a sensitivity analysis around transmission and distribution (T&D) costs and material/installation costs on solar PV measure permutations. T&D costs were increased by 500% and technology costs were decreased by 35%. Neither change, on their own, allowed solar PV permutations to pass the TRC.

end-uses, provided they possess similar characteristics as identified by the k-means clustering technique. Further details on these bundles are included in the following sub-section.

7.8.1.2 Adjustments to EE IRP Inputs

Two adjustments to the Market Potential Study's program energy efficiency potential savings, and one direct adjustment to costs, were necessary prior to inclusion in the IRP. The first adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on I&M's Peak Demand Line Loss Factors to convert savings from the meter level up to the generator level.[25]

The second savings adjustment, referred to as a "Supplemental Efficiency Adjustment (SEA)" is included to align the projections of future energy efficiency potential with the embedded efficiency trends already included in the I&M load forecast as discussed in Section 5.6.2. Also discussed in the load forecast section, the sales forecast developed for the Market Potential Study does not include any projections of energy efficiency beyond prevailing building codes and equipment standards, while the I&M load forecast used for the IRP does include implicit assumptions about future energy efficiency. The SEA functions to net out incremental efficiency already embedded in the IRP load forecast.

The SEA adjustment begins by calculating the weighted average Effective Useful Life (EUL) of each incremental annual EE bundle. The lifetime savings of each individual measure included in the EE bundle is assigned the overall bundles weighted average EUL to maintain a consistent estimate of lifetime savings impacts. Finally, a SEA matrix (either 5-year, 10-year, 15-Year, or 20-year) was applied to the annual stream of lifetime savings (based on the weighted average EUL) to account for the portion of future year savings that are assumed to already be reflected in the I&M sales forecast.[26]

On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided transmission and distribution (T&D) benefit associated with DSM measures, the GDS Team provided I&M and Siemens with energy efficiency (and demand response) costs that have been adjusted to net out the avoided T&D benefit, see 7.5.2 for the discussion on Avoided Costs.

The GDS team provided the energy efficiency IRP inputs across three different vintage bundles: 2023-2025, 2026-2028, and 2029-2040 to better optimize the value of energy efficiency to the system over time periods that align with subsequent I&M planning periods. The energy efficiency MWh and MW impacts for each vintage block provide the cumulative annual lifetime savings. Conversely, because energy efficiency program costs are only incurred during the year of measure

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[25] I&M's peak demand line loss factors were used for adjusting both energy and demand savings from the customer meter up to generation. The peak demand line loss factor was used a proxy for marginal line loss factors, which have not been studied by I&M.

[26] The 5-year, 10-year, 15-Year, or 20-year SEA matrixes were assigned based on each incremental annual EE bundles weighted average EUL. A weighted average annual EUL of 5-years or less was assigned the 5-year SEA matrix, an EUL of 10-years or less was assigned the 10-year matrix, etc.

installation, budgets are only reflected during the identified years in each vintage block. The energy efficiency resources provided to I&M for IRP modeling, are discussed below in the next section. The modeled bundle savings are found in Appendix E.

7.8.1.3 Time-Differentiated Savings

The AURORA software views demand-side resources as non-dispatchable “generators” that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it “generates” energy.

In addition to the annual impacts shown in the tables above, typical hourly (8,760) shapes for each EE bundle, that reflect the various measures and end-uses reflected in each EE bundle, were provided to the I&M modeling team to permit the IRP model to assess the value of energy savings on an hourly basis. The GDS Team disaggregated the EE bundle savings based on the same end-use load shapes utilized in the market potential in order to produce an overall bundle 8,760 savings profile. As a result. the 8,760 shapes are unique for each EE sector and vintage bundle.

7.8.1.4 Alternative EE IRP Input Scenarios

As part of the IURC Cause 45546 settlement, the Company agreed to model portfolios utilizing a Net-to-Gross (NTG) adjustment factor in place of the previously described SEA factor. Two additional bundles with the NTG factor applied were prepared to support an RTA Scenario and the Reference Scenario portfolios.

The measure/bundle assignment was not altered for the NTG factor bundles and in both the SEA and NTG bundles, the gross program savings were the same. In addition, the first adjustment (noted in 7.8.1.2) to the Market Potential Study’s program energy efficiency potential was also carried forward in the NTG Factor IRP inputs to adjust to savings at the generator level.

In the NTG factor IRP bundles, a second adjustment converted the projected gross program savings estimates to net savings using I&M’s most recent program evaluation results but does not assume that customers will adopt more efficient technologies outside of a utility sponsored program. This is in contrast to the SEA factor approach, which utilized gross program savings but assumes a weighted average effective useful life (EUL) for all measures in each bundle and adjusts the same projected gross program savings to account for the future customer adoption of efficient technologies already considered in the load forecast.

In addition to the SEA and NTG factor EE IRP inputs developed for a Reference Scenario, the GDS Team provided a set of EE bundles for the RTA Scenario. Those inputs were developed consistent with the approach outlined above but were based on an MPS scenario that assumed all measure costs (and associated incentives) were reduced by 35%.

7.8.2 Demand Response IRP Inputs

Levels of DR potential for summer peak demand reduction associated with RAP and MAP scenarios were provided as inputs to the IRP. Each scenario's reductions were divided into two bins based on resource type, whether a dispatchable, or callable, DR resource or a fixed DR resource. Time-of-use rate programs make up the only fixed DR resource in the RAP and MAP scenarios. All other programs in the scenarios were dispatchable resources.

Program cost outputs from the potential study were formatted as required by the IRP into annual program costs for each sector, scenario, and resource type. Program costs were shown in the year of their occurrence and not annualized over the life of the program. Table 14 and Table 15 shows the levels of DR potential provided for Dispatchable and Fixed DR programs.

Table 14. Dispatchable DR Scenario Inputs

	RAP				MAP			
	Residential		C&I		Residential		C&I	
	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
2023	6.01	$222.58	0.80	$1,377.45	7.22	$246.57	0.93	$1,160.15
2027	28.50	$76.77	17.99	$78.04	36.14	$89.38	15.90	$62.83
2032	56.17	$38.61	42.04	$34.04	79.90	$50.18	42.99	$29.85
2042	65.52	$33.61	46.50	$29.71	110.72	$44.31	48.52	$23.07

Table 15. Fixed DR Scenario Inputs

	RAP				MAP			
	Residential		C&I		Residential		C&I	
	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)	DR MW Summer Peak Impact (Cumulative)	Annual Program Costs (Nom $/kW-yr)
2023	0.67	$270.76	0.03	$2,709.98	0.94	$279.94	0.03	$2,619.97
2027	4.51	$46.81	0.63	$125.17	6.90	$62.61	0.54	$171.22
2032	8.24	$13.20	1.49	$52.63	12.79	$12.34	1.75	$47.20

The DER analysis ultimately found all modeled solar PV and CHP resources were not cost effective according to the Total Resource Cost (TRC) Test. The TRC Test was selected as the primary cost-effectiveness screening test for DERs to encapsulate both utility and customer perspectives and determine whether a utility-sponsored program intervention is prudent. Ultimately, no solar PV or

CHP technologies passed cost-effectiveness screening under the TRC.[27] As a result, achievable market potential was not assessed.

While the analysis shows that DER is not cost effective from the customer perspective, the Company did include in the IRP modeling an assumed level of incremental DER.

7.8.3 DER IRP Inputs

Although the I&M MPS found no cost-effective achievable potential (under current avoided costs and cost-effectiveness screening parameters) from DERs, the GDS Team performed additional modeling based on a business-as-usual scenario to understand how future DER growth may occur in the territory at its current trajectory with no utility intervention. This scenario was modelled based on primary data reported from its customers on data for willingness to adopt DER technologies without any utility incentive. Forecasted incremental generation additional to existing capacity for solar PV and CHP over the study horizon is presented in Table 16 below. The maximum MW impact of the DER resources is also shown in the table below. This forecast was utilized in all Candidate Portfolios.

Table 16. DER Forecasted Generation

Year	Solar PV - BAU (MWh)	CHP - BAU (MWh)	Max (MW)
2023	2,377	41	1.05
2027	5,862	107	2.71
2032	15,224	297	9.45
2042	160,970	1,898	71.09

7.8.4 Conservation Voltage Reduction (CVR)

The future potential for CVR is based on the number of remaining distribution substations where CVR can be cost effectively deployed and operated in I&M's energy delivery system. The Company performed cost effective analysis for the distribution substation busses (i.e., the electrical point of common connection for a set of distribution circuits, typically a set of three circuits) that do not currently have CVR deployed. The analysis estimated cost effectiveness underestimated CVR operational and performance parameters using AMI technology and resulted in an additional 420 distribution circuits, comprised of 343 in I&M's Indiana jurisdiction and 77 in I&M's Michigan jurisdiction. The total energy and peak demand savings from this CVR potential is estimated at approximately 230 GWh of energy savings and 75 MW of demand savings through 2027.

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[27] The GDS Team conducted a sensitivity analysis around transmission and distribution (T&D) costs and material/installation costs on solar PV measure permutations. T&D costs were increased by 500% and technology costs were decreased by 35%. Neither change, on their own, allowed solar PV permutations to pass the TRC.

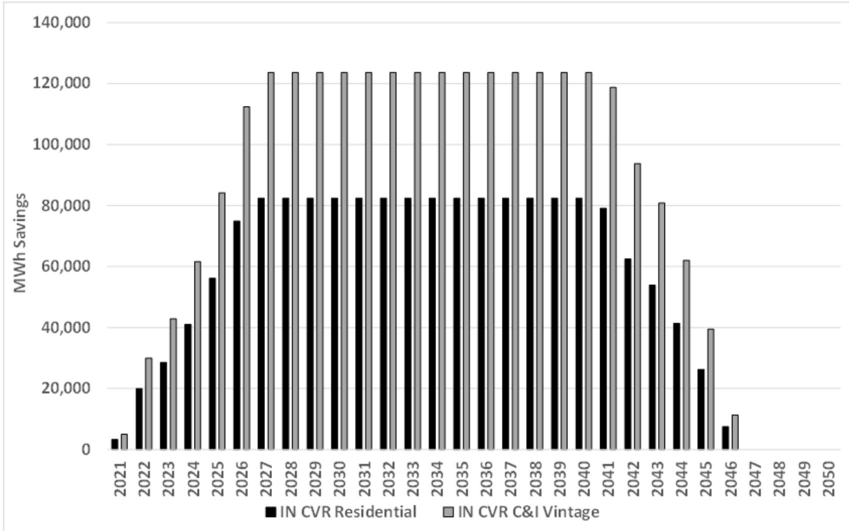


Figure 38. Indiana CVR Forecast Energy Savings

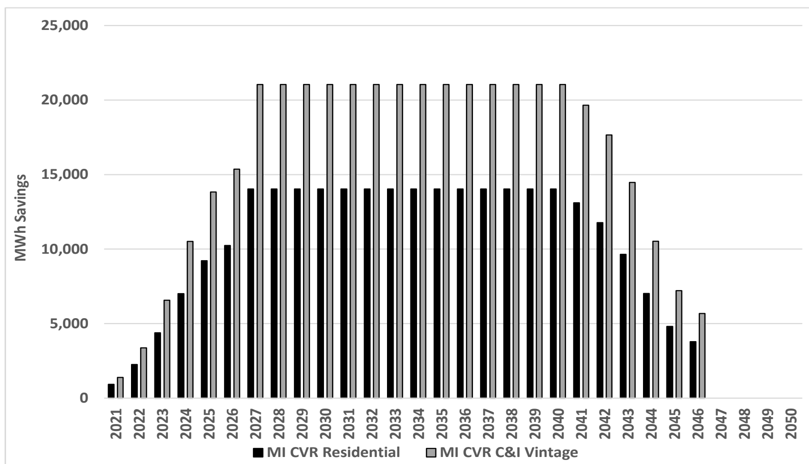


Figure 39. Michigan CVR Forecast Energy Savings

7.9 Integration of Demand-Side Options within AURORA Modeling

Siemens PTI, the GDS Team and the I&M IRP team collaborated on the development of the forecasted inputs needed to include DSM Resources in the analysis. In the IRP analysis, the DSM options included EE, DR and distributed energy resources (DER) and over 50 programs were modeled. Each supply-side and several demand-side resources were offered into the AURORA model as descripted below. Each resource has specific values for capacity, energy production (or savings) and cost.

Table 17. DSM Resource Treatment

Measure	Program	Treatment	# of Programs
Energy Efficiency	Conservation Voltage Reduction (CVR)	Going-In	4
	Low Income Qualified (IQW)	Going-In	3
	Michigan 2022 EE Plan	Going-In	1
	Long-Term Vintages	Optimized	39
Demand Response	Residential	Non-Optimized	1
	Commercial & Industrial	Non-Optimized	1
Distributed Energy Generation	Rooftop Solar (DG)	Going-In	2
	Combined Heat & Power (CHP)	Going-In	1

Going In: These programs will be included as part of the going-in position of I&M's portfolio, regardless of cost.

Optimized: These programs will be exposed to the optimization routine, and the capacity and generation impact will be determined by the economic need for these programs.

Non-Optimized: The capacity is included as part of I&M's going in resource; however, the actual impact to each Portfolio depends on the economic dispatch of the program. DR programs are applied for three continuous hours for I&M's top five days of demand, totaling 15 hours each year. DER and EE capacity and shapes are represented by the information provided by GDS analysis. The economic benefit of these programs is not evaluated in the IRP analysis.

7.10 Candidate Portfolios

As discussed in Section 3, I&M Candidate Portfolios were developed utilizing AURORA's LTCE modeling for the Reference and other portfolios. I&M and Siemens developed over 14 portfolios as part of the IRP Process which included the Preferred Portfolio and additional portfolios for other settlement agreement requirements. In addition to the Reference Portfolio, the IRP considered 10 Sensitivities off the Reference Portfolio and two alternative scenarios with an additional sensitivity off of the Rapid Technology Advancement scenario. The approach is to implement a scenario- and sensitivity-based approach to create Candidate Portfolios and to ultimately test which portfolios perform the best over a wide range of future market and regulatory conditions.

Table 18. Reference and Potential Candidate Portfolios

Portfolio Name	Description
Reference Case (Original)	Rockport Unit 1 (2028) Rockport Unit 2 (2024) and Cook (2034, 2037)
Rockport 1 2024	Rockport Unit 1 Early Retirement (2024)
Rockport 1 2025	Rockport Unit 1 Early Retirement (2025)
Rockport 1 2026	Rockport Unit 1 Early Retirement (2026)
Cook 2050+	Cook Unit 1 and Unit 2 License Extensions (beyond 2034 and 2037)
Cook 2050+ and No Gas	Cook Unit 1 and Unit 2 License Extensions and No Conventional Gas
Expanded Build Limits	Expanded Cumulative Build Limits on Renewable Energy and Storage
Reference'	Reference Case (Original) with an Import and Export Limit at ~30% of I&M Load
Rapid Technology Advancement	35% Reduction in Renewable, Storage and EE Costs
Enhanced Regulation	Increased Environmental Regulations Leading to High Gas, Coal and CO2 Prices
Rockport 1 2024 N2G	Rockport Unit 1 Early Retirement (2024) Replacing SEA with Net to Gross EE Bundle Savings
Rockport 1 2026 N2G	Rockport Unit 1 Early Retirement (2026) Replacing SEA with Net to Gross EE Bundle Savings
Rapid Technology Advancement N2G	Rapid Technology Advancement (RTA) Replacing SEA with Net to Gross EE Bundle Savings
Reference with No Renewable Limits	Removed cumulative Build Limits on Renewable Energy and Storage

7.11 Probabilistic (Stochastic) Distributions

Probabilistic modeling incorporates several market variables and probability distributions into the analysis. The approach is integral to the 5-Step IRP Process, allowing for the evaluation of a portfolio's performance over a wide range of market conditions. The Balanced Scorecard is populated from data that is extracted from the results of the probabilistic modeling and is the foundation to inform the risk analysis.

Probabilistic modeling begins with the simulation of 200 sets of future pathways for coal prices, natural gas prices, carbon emission prices, peak and average load, and capital costs for a range of technologies. Each of these stochastic variables is propagated to the end of the study period and was informed by boundary conditions provided through a High and Low fundamental forecast and High and Low load forecasts by AEP. The high and low forecasts were informed by EIA reports. These 200 iterations of each stochastic variable are then loaded as inputs into the dispatch model of AURORA. These inputs thus allow for the testing of each portfolio's performance across a wide range of market conditions. These inputs can be seen in the following set of Figures.

All Portfolios were subjected to each of the 200 iterations using AURORA in dispatch mode where the I&M portfolio is fixed but other PJM members can make decisions under each market scenario.

7.11.1 Load Stochastics

To account for electricity demand variability that derives from economic growth, weather, energy efficiency, and demand side management measures, Siemens PTI developed stochastics around the average and peak load growth expectations for the I&M control area and the neighboring ISO zones. The stochastic distributions for I&M average and peak load can be seen in the Figure 40 below.

The Siemens PTI's long-term load forecasting process for neighboring utilities and zones follows a two-step process that captures both the impact of historical load drivers such as economic growth and variability in weather and the possible disruptive impacts of energy efficiency penetration, distributed generation penetration, and the widespread adoption of electric vehicles in constructing the average and peak demand outlook.

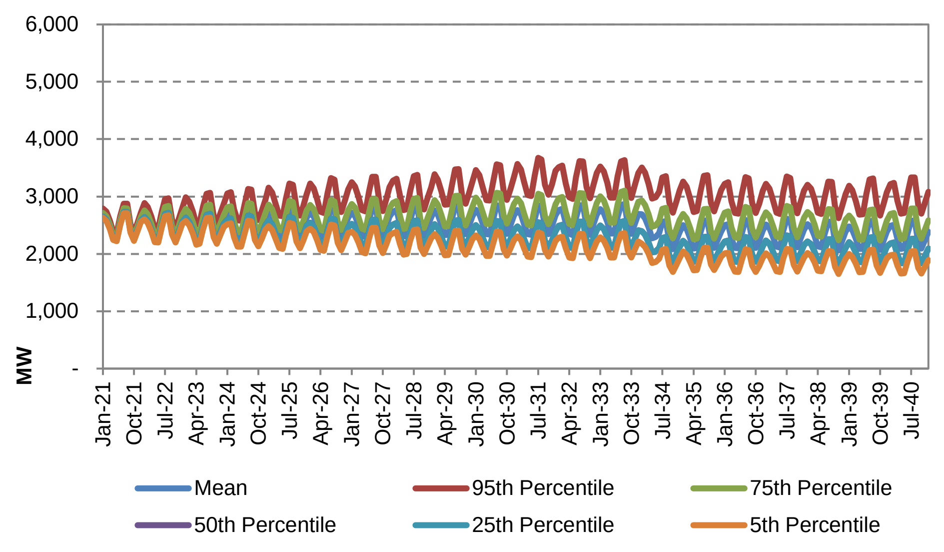


Figure 40. I&M Average Monthly Load

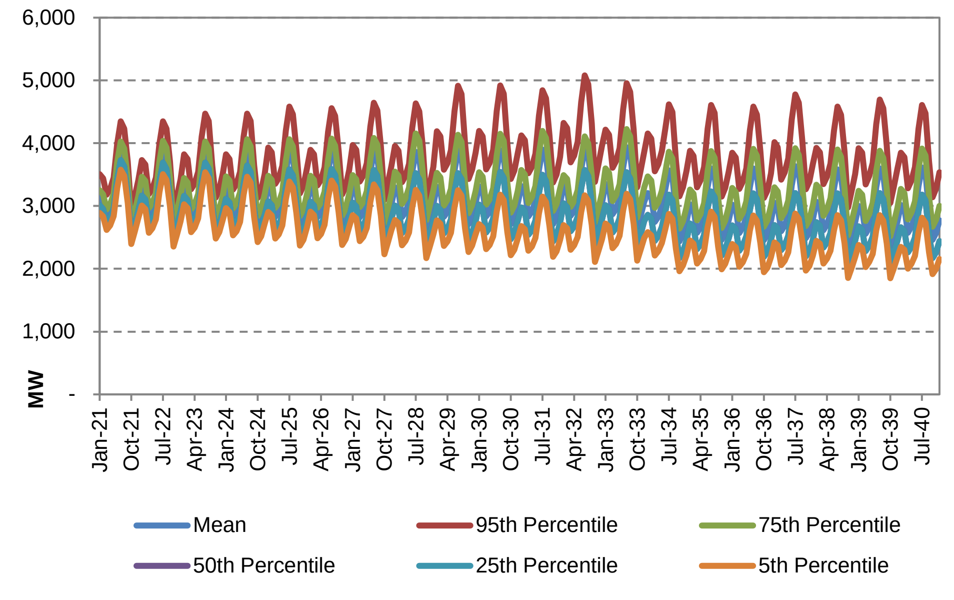


Figure 41. I&M Peak Monthly Load

7.11.2 Gas Stochastics

Siemens PTI developed natural gas price stochastic distributions for the benchmark Henry Hub market point. These stochastic distributions are first based on the Reference Scenario view of natural gas prices with probability bands developed then based on a combination of historical volatility and mean reversion parameters as well as a forward view of expected volatility. For the period 2021-2024, volatility calculated from the past three years of price data is used. For 2025-2027, volatility calculated from the past five years is used. For 2028-2041, volatility calculated from the past 10 years is used. This allows gas price volatility to be low in the short-term, moderate in the medium-term and higher in the long-term in alignment with observed historical volatility. The 95th percentile probability bands are driven by increased gas demand (e.g., coal retirements) and fracking regulations that raise the cost of producing gas. Prices in the 5th percentile are driven by significant renewable development that keeps gas plant utilization relatively low as well as few to no new environmental regulation around power plant emissions.

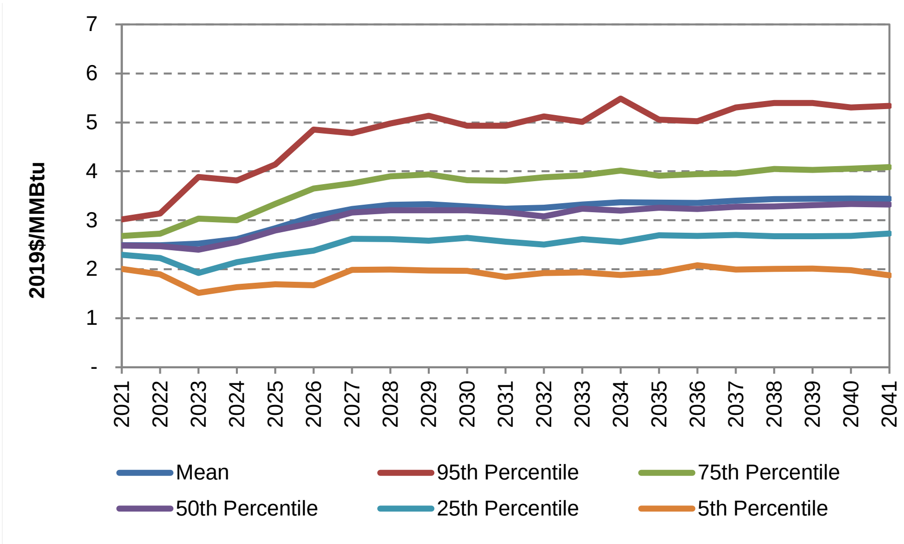


Figure 42. Henry Hub Stochastic Annual Price

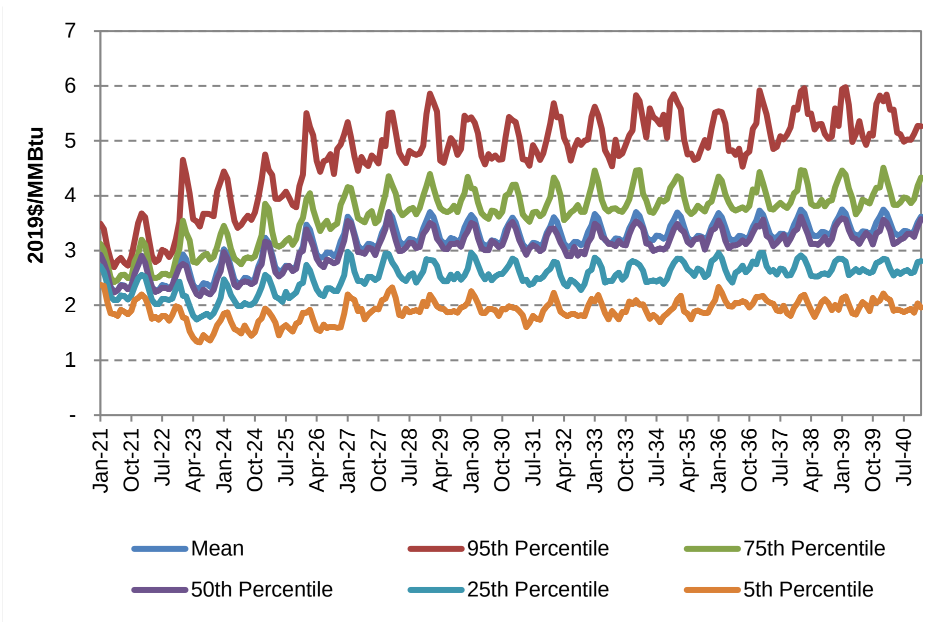


Figure 43. Henry Hub Stochastic Monthly Price

7.11.3 Coal Stochastics

Siemens PTI developed coal price stochastic distributions for the CAPP, NAPP, ILB and PRB basins. These stochastic distributions are first based on the Reference Scenario view of coal prices with probability bands developed, then based on a combination of historical volatility and mean reversion parameters. It should be noted that most coal contracts in the U.S. are bilateral and only approximately 20% are traded on the New York Mercantile Exchange (NYMEX). The historical data set that is used to calculate the parameters is comprised of the weekly traded data reported in NYMEX.

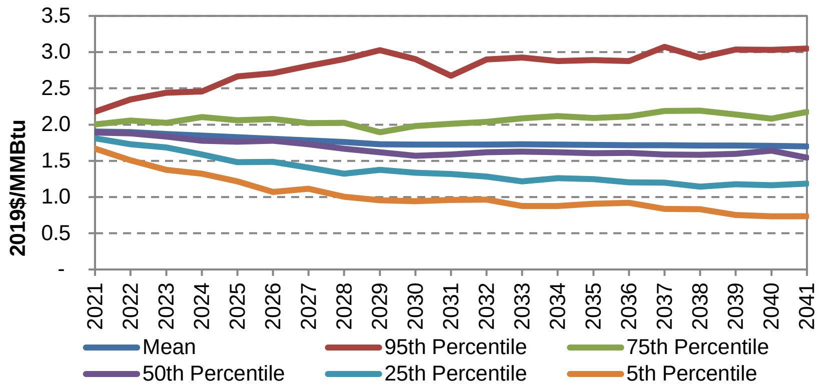


Figure 44. Stochastic Illinois Basin Coal Price

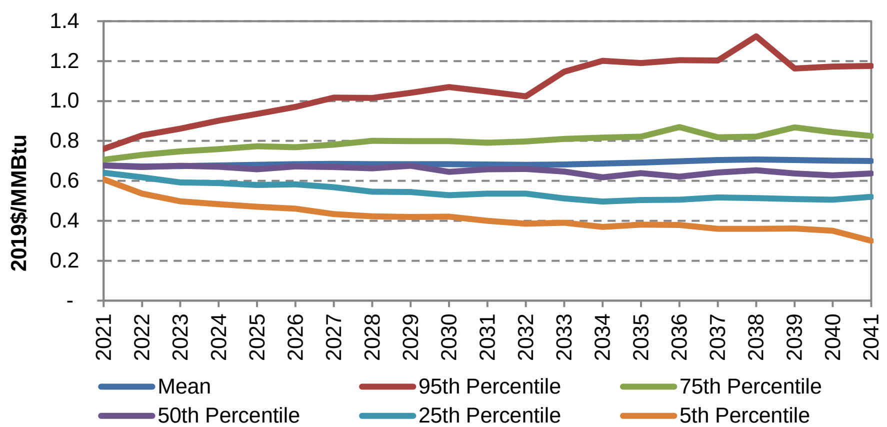


Figure 45. Stochastic Powder River Basin Coal Price

7.11.4 Capital Cost Stochastics

Siemens PTI developed the uncertainty distributions for the cost of new entry units by technology type, which was used in AURORA for determining the economic new builds based on market signals. These technologies included gas peaking units, gas combined cycles units, solar, wind, and battery storage resources. The methodology of developing the capital cost distributions is a two-step process: (1) a parametric distribution based on a Reference Scenario view of future all-in capital costs, historical costs, and volatilities, and a sampling of results to develop probability bands around the Reference Case; and (2) a quantum distribution that captures the additional uncertainty with each technology that factors in learning curve effects, improvements in technology over time, and other uncertain events such as leaps in technological innovation.

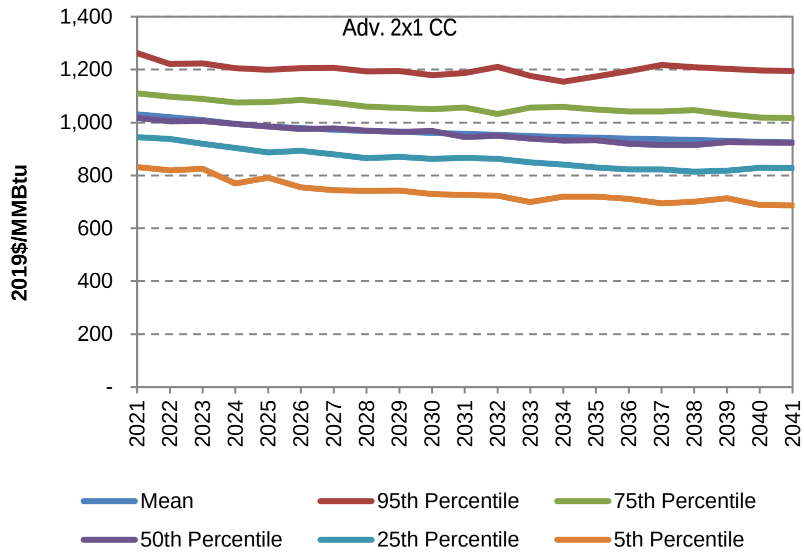


Figure 46: Stochastic Gas Combined Cycle Capital Cost

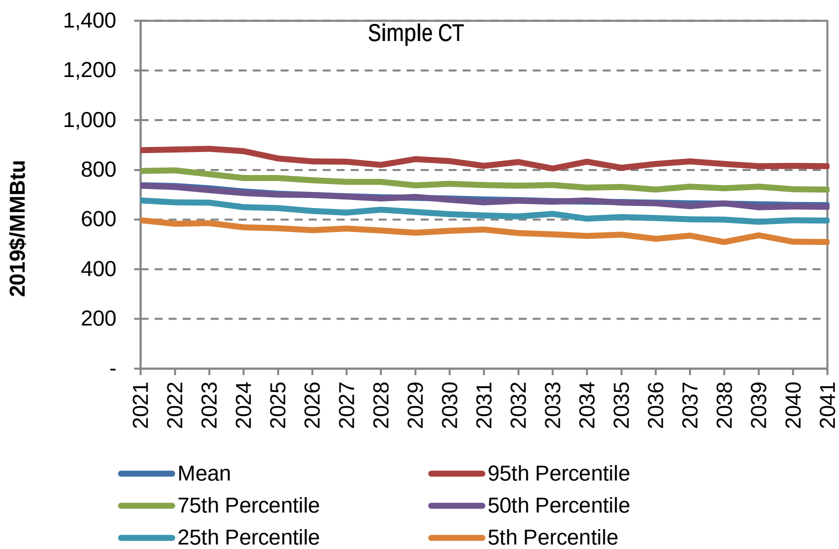


Figure 47: Stochastic Simple Frame Combustion Turbine Capital Cost

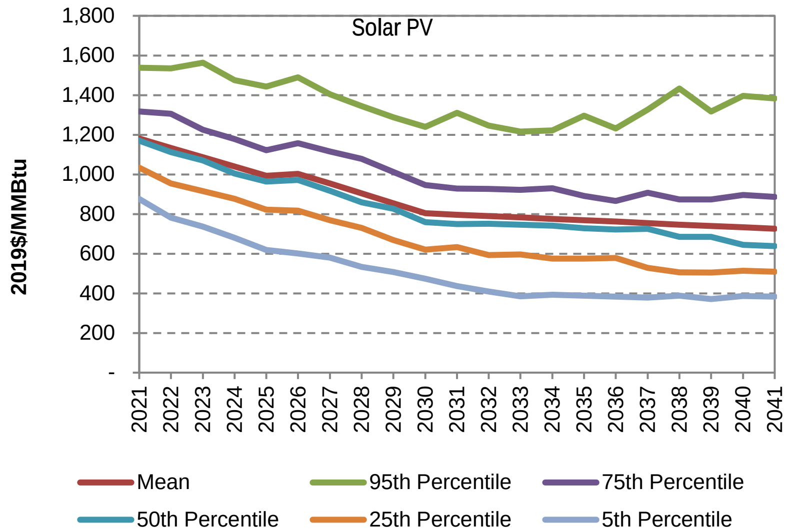


Figure 48: Stochastic Solar PV Tracking Capital Cost

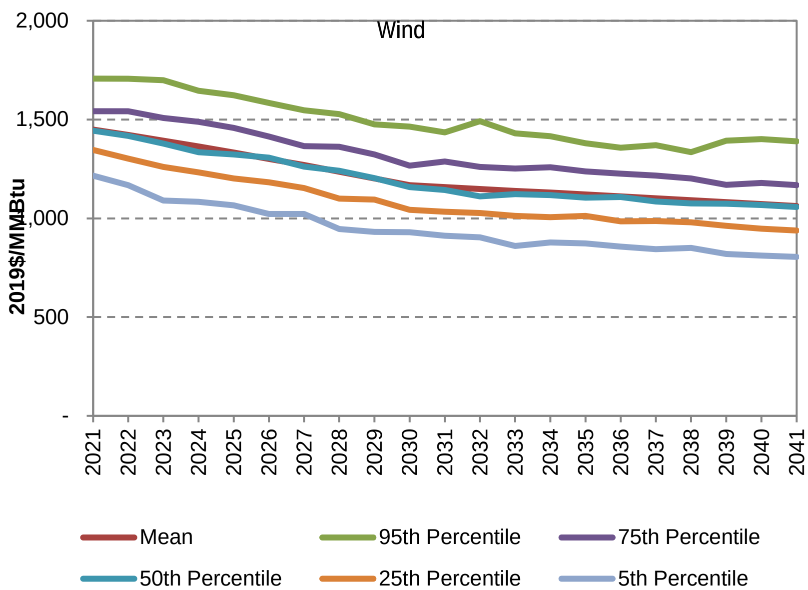


Figure 49: Stochastic Simple Frame Combustion Turbine Capital Cost

7.11.5 National CO_2 Emission Price

Siemens PTI developed uncertainty distributions around carbon compliance costs, which were used in AURORA to capture the inherent risk associated with regulatory compliance requirements. The technique to develop carbon costs distributions, unlike the previous variables, is based on projections largely derived from expert judgment, as there are no national historical data sets (only regional markets in California and the northeast U.S.) to estimate the parameters for developing carbon costs distributions. The Reference Scenario CO_2 price outlook reflects a view that some type of legislation will likely occur in the late-2020s to provide incentives for faster shifts from fossil to renewable generation. The bottom end of the distribution assumes no future regulation.

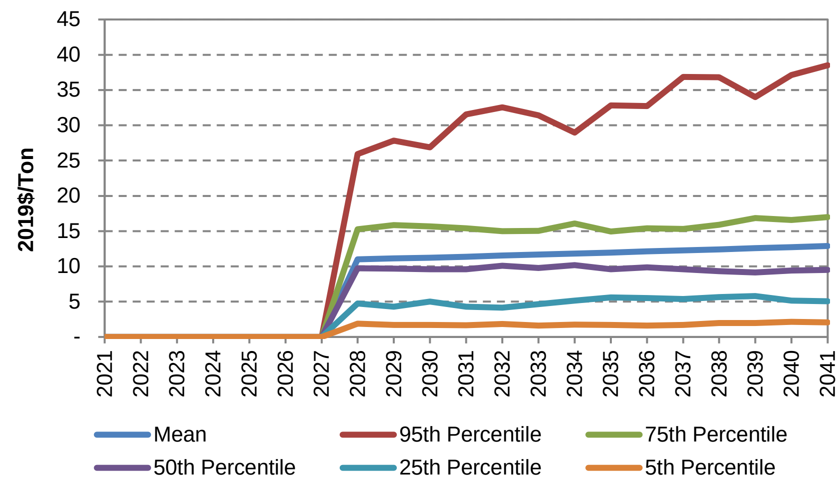


Figure 50. Stochastic CO_2 Price

7.11.6 Cross-Commodity Stochastics

Siemens PTI captured the cross-commodity correlations in the stochastic process, which is a separate stochastic process from those for gas, coal, and CO_2 prices. The feedback effects are based on statistical relationships between coal and gas switching and the variable cost of coal and gas generators. Siemens conducted a fundamental analysis to define the relationship between gas and coal dispatch costs and demand. The dispatch costs of gas and coal were calculated from the gas and coal stochastics and CO_2 stochastics, along with generic assumptions for variable operation and maintenance costs. Where the gas-coal dispatch differential changes significantly enough to affect demand, gas demand from the previous year was adjusted to reflect the corresponding change in demand. A gas price delta was then calculated based on the defined gas demand. This gas price delta was then added to the gas stochastic path developed from historic volatility to calculate an integrated set of CO_2 and natural gas stochastic price forecasts.

8 Portfolio Development

As an integral step in the IRP process, I&M developed several “potential” Candidate Portfolios for analysis in Step 3 of the IRP Process. Each of these portfolios represents a potential strategic resource planning decision, alternative potential future market condition(s), or various regulatory requirements.

Key performance indicators (KPI) are used to demonstrate the viability and merits of each individual portfolio in Step 3 of the IRP Process. It is important to note this step of the analysis is meant to evaluate each individual portfolio and not compare portfolios amongst themselves. The goal is to identify resulting Candidate Portfolios that represent a variety of strategic alternatives for further analysis. The group of selected Candidate Portfolios then advance to the IRP Step 4: Portfolio Analysis where they are analyzed to develop comparative measures (metrics) for presentation in the Balanced Scorecard.

I&M evaluated a total of 14 Candidate Portfolios for initial review which were identified and developed during the IRP process based upon multiple sources of input, including feedback received in Stakeholder meetings 1, 2, and 3A (including supplementary comments received), the review of Siemens PTI and I&M, and I&M’s Settlement Agreement in Cause No. 45546. The potential Candidate Portfolios included potential strategic decisions around Rockport retirement dates, Cook license extensions, a high-renewable future and two Scenarios offering varying future states of the world to reflect rapid technology advancements and enhanced regulations. The potential Candidate Portfolios offered varying strategic insights and potential decisions to transition I&M’s portfolio through the retirement of the Rockport units by 2028 and the remaining IRP planning period.

The potential Candidate Portfolios and KPIs were presented and discussed with Stakeholders during Stakeholder Meeting #3B and were advanced to Step 4: Portfolio Analysis, in order to further the detailed analysis around all identified portfolios. Two additional metrics were added to the Balanced Scorecard in response to stakeholder input as described in section 2.5.2.: 1) the 5-Year Net Rate Increase CAGR (2025-2029), and 2) Average Number of Unique Generators in order to more thoroughly assess affordability and rate stability. Additionally, two metrics were modified from end of plan year values to average values over the planning period.

The resulting evaluation from Step 4: Portfolio Analysis including the Balanced Scorecard results were presented during the final Stakeholder meeting.

8.1 Candidate Portfolio Descriptions

The following section describes the designed set of Candidate Portfolios. The table below provides a summary of each of the 14 selected portfolios’ capacity additions and retirements that were then analyzed in the Step 4 for the development of comparative metrics.

Table 19. Candidate Portfolios and Descriptions

Portfolio Name	Description
Reference Case (Original)	Rockport Unit 1 (2028) Rockport Unit 2 (2024) and Cook (2034, 2037)
Rockport 1 2024	Rockport Unit 1 Early Retirement (2024)
Rockport 1 2025	Rockport Unit 1 Early Retirement (2025)
Rockport 1 2026	Rockport Unit 1 Early Retirement (2026)
Cook 2050+	Cook Unit 1 and Unit 2 License Extensions (beyond 2034 and 2037)
Cook 2050+ and No Gas	Cook Unit 1 and Unit 2 License Extensions and No Conventional Gas
Expanded Build Limits	Expanded Cumulative Build Limits on Renewable Energy and Storage
Reference’	Reference Case (Original) with an Import and Export Limit at ~30% of I&M Load
Rapid Technology Advancement	35% Reduction in Renewable, Storage and EE Costs
Enhanced Regulation	Increased Environmental Regulations Leading to High Gas, Coal and CO2 Prices
Rockport 1 2024 N2G	Rockport Unit 1 Early Retirement (2024) Replacing SEA with Net to Gross EE Bundle Savings
Rockport 1 2026 N2G	Rockport Unit 1 Early Retirement (2026) Replacing SEA with Net to Gross EE Bundle Savings
Rapid Technology Advancement N2G	Rapid Technology Advancement (RTA) Replacing SEA with Net to Gross EE Bundle Savings
Reference with No Renewable Limits	Removed cumulative Build Limits on Renewable Energy and Storage

A summary of the Candidate Portfolio near-term and long-term resource additions identified in Step 3 is shown in Table 20. Appendix Vol. 1, Exhibit C includes the annual resource additions by Portfolio, type and year.

Table 20. Candidate Portfolio Capacity Changes

	2022 - 2028 Additions							2029 - 2041 Retirements and Additions					
	Capacity Additions (MW)							Capacity Additions (MW)					
Portfolio	Wind	Solar	Storage	Gas CT	Gas CC	EE*	Market*	Wind	Solar	Storage	Gas CT	Gas CC	EE*
Reference Case	1,600	1,800	160	750	0	189	-314	0	0	0	1,250	1,070	124
Rockport 1 - 2024	1,600	1,800	380	500	0	208	-1,569	0	0	0	1,250	1,070	140
Rockport 1 - 2025	1,600	1,800	460	500	0	204	-314	0	700	0	1,000	1,070	124
Rockport 1 - 2026	1,600	1,800	80	750	0	194	-314	0	0	0	750	1,070	140
Cook 2050+	1,600	1,800	160	750	0	189	-314	0	0	0	0	0	117
Cook 2050+ and No Gas	1,600	1,800	850	0	0	234	-314	0	0	150	0	0	121
Expanded Build Limits	2,400	2,700	240	250	0	217	-314	0	250	0	1,000	1,070	131
Reference'	1,600	1,800	60	750	0	234	-314	0	150	0	1,000	1,070	180
Rapid Technology Advancement	1,600	1,800	160	750	0	179	-313	4,200	1,050	50	1,250	0	136
Enhanced Regulation	1,600	1,800	160	750	0	223	-314	4,200	1,050	0	1,250	0	156
Rockport 1 2024 N2G	1,600	1,800	460	500	0	174	-1,568	0	0	0	1,250	1,070	231
Rockport 1 2026 NTG	1,600	1,800	100	750	0	165	-313	0	0	0	1,000	1,070	306
Rapid Technology Advancement N2G	1,600	1,800	160	750	0	162	-314	4,200	1,100	0	1,250	0	273
Reference with No Renewable Limits	6,000	6,000	600	0	0	189	-314	0	0	0	750	0	124

*EE Capacity represents total capacity available in 2028 and 2041
*EE Capacity represents maximum capacity of all programs and does not represent output at I&M peak demand hour
**Market Capacity represents capacity shortfall in the year 2024 for the portfolios

8.2 Reference Portfolio (Original)

The Reference Case reflects the model's selection of the most economic resource additions using base forecast assumptions. It includes a combination of solar, wind and hybrid through 2027 and CT additions in 2028 to fill I&M's capacity and energy requirements created by the retirement of the Rockport Plant by 2028. Cook Unit 1 and 2 operations continue through 2034 and 2037, respectively, where they are replaced with a combination of Gas CT and CC additions to account for the necessary baseload capacity and energy that is lost. In addition to the supply-side resources, a diverse mix of energy efficiency resources were included across three vintages that peak at 246 MW in 2033. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.3 Reference Portfolio Sensitivities

Several alternatives to the Reference Portfolio were analyzed. These included three Rockport retirement alternatives requested by Stakeholders and determined through settlement agreements with the Company to analyze an earlier retirement of Rockport unit 1. Additional alternative strategies were identified by I&M including the analysis related to extending the Cook Nuclear facility operating life and alternative constraints related to annual resource build limits and the management of energy imports and exports.

Note: Candidate portfolios were designed with combinations of hybrid and stand-alone solar and storage technologies. Hybrid and stand-alone solar and storage are combined for reporting in Table 20.

8.3.1 Rockport Unit 1 – 2024

The Rockport Unit 1 – 2024 early retirement Candidate Portfolio retires the Rockport Unit 1 plant four years earlier than its planned retirement in 2028. In comparison to the Reference portfolio, Rockport Unit 1 – 2024 replaces CT capacity with standalone storage due to the availability of resources in the earlier years. In addition to the standalone storage, Rockport Unit 1 – 2024 portfolio includes a similar mix of wind, solar and hybrid resources in the early years as the Reference portfolio as well as CT and CC capacity additions in the later years as a replacement for the assumed (for modeling purposes) Cook Unit 1 and 2 retirements. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 286 MW in 2034. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.3.2 Rockport Unit 1 – 2025

The Rockport Unit 1 -2025 early retirement Candidate Portfolio retires the Rockport Unit 1 plant three years early. Similar to Rockport Unit 1 – 2024 portfolio, Rockport Unit 1 – 2025 has additional standalone storage as a replacement for Rockport 1 early retirement in place of some CT capacity. Rockport Unit 1 – 2025 portfolio includes a similar mix of wind, solar and hybrid resources in the early years along with additional standalone storage to account for the larger capacity need in 2025 due to Rockport 1 retirement. Like the Reference and Rockport Unit 1 – 2024 portfolios, Cook Unit 1 and 2 operations are assumed for modeling purposes to continue through 2034 and 2037, respectively, and are replaced with a combination of CT and Gas CC additions to account for the necessary baseload capacity that is lost. Unlike the previous portfolios, Rockport Unit 1 – 2025 exchanges some CT capacity in the later years for solar additions. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 243 MW in 2032. All shortfalls in capacity are met through capacity market purchases.

8.3.3 Rockport Unit 1 – 2026

The Rockport Unit 1 - 2026 early retirement Candidate Portfolio retires the Rockport Unit 1 plant two years early. Rockport Unit 1 – 2026 portfolio includes is largely identical to the Reference portfolio with the exception of slight timing adjustments and tradeoff between standalone solar and hybrid resources as well as earlier CT additions to replace the Rockport capacity lost in 2026. The Cook units operations remain the same as the reference portfolio and are replaced with similar CT and CC capacity additions in later years. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 286 MW in 2034. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.3.4 Cook 2050+

The Cook 2050+ Candidate Portfolio extends the licenses of the Cook Nuclear facilities for 20 years, beyond the end of the study period. The Cook 2050+ Candidate Portfolio includes an identical mix of resources as the Reference Portfolio to replace the Rockport Units 1-2 capacity. Cook Unit 1 and 2 operations continue through 2050+ whereas no further portfolio additions are necessary. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 247 MW in 2033. Additionally, any further capacity shortfalls in capacity are met through short-term annual capacity market purchases. Fuel, Variable O&M and Fixed O&M Costs for the extended life of the Cook Units in the Cook 2050+ Portfolio were applied to the projected generation and accounted for out of the model and added to the Portfolio CTSL projections. A fuel cost adjustment was made for the additional years in the planning period and involved taking the latest year available (2034 for Cook 1 and 2037 for Cook 2) fuel cost on a $/MWh basis and assuming a 2% inflation increase to the nominal cost..

8.3.5 Cook 2050+ and No Gas Allowed

The Cook 2050+ and No Gas Allowed Candidate Portfolio extends the licenses of the Cook Nuclear facilities for 20 years, beyond the end of the study period, and removes all gas resources from the optimization routine. The Cook 2050+ and No Gas Allowed portfolio has a similar mix of solar, wind and hybrid resources in the early years to replace Rockport Unit 2 capacity. Rockport Unit 1 capacity is replaced with standalone storage in the Cook 2050+ and No Gas Allowed Portfolio. Cook Unit 1 and 2 operations continue through 2050+ whereas no further additions are necessary other than a few additional storage units to account for depreciating efficiency in earlier storage units. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 293 MW in 2031. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases. Fuel, Variable O&M and Fixed O&M Costs for the extended life of the Cook Units in the Cook 2050+ Portfolio were applied to the projected generation and accounted for out of the model and added to the Portfolio CTSL projections. A fuel cost adjustment was made for the additional years in the planning period and involved taking the latest year available (2034 for Cook 1 and 2037 for Cook 2) fuel cost on a $/MWh basis and assuming a 2% inflation increase to the nominal cost.

8.3.6 Expanded Build Limits

The Expanded Build Limits Candidate Portfolio expands annual and cumulative resource limits and was constructed to test the resource limits. The optimized Expanded Build Limits portfolio increases the amount of all renewable options in the early years as the limits allow and fewer CT units as there is more renewable capacity. Cook Units 1 and 2 capacity are replaced with a combination of Solar, CT and Gas CC additions to account for the necessary baseload capacity that is lost. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 299 MW in 2034. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.3.7 Reference' (Reference Prime)

The Reference' Candidate Portfolio technology mix was optimized in Step 3, as described section 3.4.3 with an import and export limit at approximately 30% of load. Importantly, the import and export limits were not applied in the Step 4 Portfolio Analysis (stochastic simulations) and therefore not reflected in the cost and performance characteristics of the Candidate Portfolios or in the balanced scorecard metrics.

The Reference' portfolio includes a similar mix of solar, wind and hybrid resources with slight changes in timing of solar additions and some tradeoff between standalone solar and hybrid resources. Cook Unit 1 and 2 capacity is replaced by the same additions as the Reference portfolio (CT and CC) with the exception of a small amount of additional solar in the later years. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 293 MW in 2031. Additionally, any further capacity shortfalls in capacity are met through short-term annual capacity market purchases.

8.3.8 Removed Build Limits

The Removed Build Limits Candidate Portfolio expands annual and cumulative resource limits even further than the Expanded Build Limits portfolio and was also constructed to test the resource limits used in the IRP. The optimized Removed Build Limits portfolio includes more of all renewable options and fewer CT units as there is more renewable capacity. Cook Units 1 and 2 capacity are replaced with a combination of Solar, Wind and Gas CT additions to account for the necessary baseload capacity that is lost. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 247 MW in 2033. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.4 Scenarios

Two scenario-based portfolios (Rapid Technology Advancement and Enhanced Regulation) were developed to evaluate various future states of the world that capture potential changes to regulatory construct, economic and market conditions and technological progress.

8.4.1 Rapid Technology Advancement

The Rapid Technology Advancement Portfolio includes an identical mix of additions as the Reference Portfolio in the early years (2022-2030) but includes a 35% reduction in renewable and storage resource technology costs. The capacity additions that replace Cook Unit 1 and 2 are largely renewable focused instead of gas driven like the Reference Portfolio. There is CT peaking capacity in the later years, but in replacement of the CC capacity, the Rapid Technology Advancement Portfolio incorporates a large amount of wind and solar capacity after 2030. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 250 MW in 2033. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.4.2 Enhanced Regulation

The Enhanced Regulation Portfolio is largely identical to the Rapid Technology Advancement portfolio which includes a similar buildout in the early years as the Reference Portfolio but replaces Cook Unit 1 and 2 capacity with CT and renewable resources post 2030. In addition to the supply-side resources, a diverse mix of energy efficiency resources were added across three vintages that peak at 287 MW in 2034. Additionally, any further capacity shortfalls in capacity are met through short-term annual capacity market purchases.

8.5 Net to Gross Sensitivities

Additional sensitivities were identified as a result of the Settlement Agreement in IURC Cause No. 45546. These sensitivities evaluated the effect of applying a Net to Gross (NTG) Energy Efficiency adjustment to the EE bundle potential savings described in section 7.8.1 and the recognized impact to the EE resource selection in the model. The NTG factor was only applied, however, to the new EE Bundle resources as described in section 7.8.1.4 while the Company's load forecast described in Section 5.6.2 remained the same.

The EE resources selected in the NTG portfolios are consistent among the three NTG portfolios discussed below. Each of the NTG portfolio's results included a smaller number of EE bundles selected, less EE savings in the earlier years of the planning period, and a higher amount of EE savings in the later years. However, the NTG approach includes and monetizes some energy efficiency savings that already are included in the Company's load forecast. In preparation for the Company's next IRP, the Company plans to study and test potential modifications to how it models EE bundles savings in the IRP modeling construct.

8.5.1 Rockport Unit 1 – 2024 Net to Gross

The Rockport Unit 1 – 2024 Net to Gross portfolio has the Rockport Unit 1 retiring four years early and replaces the EE inputs from SAE adjustment factors to NTG adjusted factors. Rockport Unit 1 – 2024 Net to Gross results include a nearly identical mix of supply-side resources as the original Rockport 1 2024 portfolio with slight changes in timings and some tradeoff between standalone solar and hybrid resources in the early year additions. Cook Unit 1 and 2 capacity replacements are identical to what was added in the Rockport 1 – 2024 portfolio. In addition to the supply-side resources, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 352 MW in 2036, keeping in mind, this includes some savings already assumed in the associated load forecast. However, the EE selected from 2023-2026 was seven MW less than the comparable portfolio. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.5.2 Rockport Unit 1 – 2026 Net to Gross

The Rockport Unit 1 – 2026 Net to Gross portfolio has the Rockport Unit 1 retire early two years early and replaces the EE inputs from SAE adjustment factors to NTG adjusted factors. Rockport Unit 1 – 2026 Net to Gross results includes a nearly identical mix of supply-side resources as the original Rockport 1 2026 portfolio with slight changes in timings and some tradeoff between standalone solar and hybrid resources in the early year additions. Cook Unit 1 and 2 operations are assumed for modeling purposes to continue through 2034 and 2037, respectively, where they are replaced with a combination of CT and Gas CC additions to account for the necessary baseload capacity that is lost. In addition to the supply-side resources, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 352 MW in 2038, keeping in mind, this includes some savings already assumed in the associated load forecast. However, the EE selected from 2023-2026 was four MW less than the comparable portfolio. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.5.3 Rapid Technology Advancement – Net to Gross

The Rapid Technology Advancement Net to Gross portfolio is based on the RTA scenario and replaces the EE inputs from SAE adjustment factors to NTG adjusted factors. The Rapid Technology Advancement – Net to Gross portfolio results includes an identical mix of supply-side resources additions in the early years to replace Rockport capacity. Cook Unit 1 and 2 operations are assumed for modeling purposes to continue through 2034 and 2037, respectively, where they are replaced with CT peaking capacity as well as reduced-cost wind and solar additions to account for the necessary baseload capacity that is lost in addition to the supply-side resources, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 451 MW in 2037, keeping in mind, this includes some savings already assumed in the associated load forecast. However, the EE selected from 2023-2026 was four MW less than the comparable portfolio. Additionally, any further capacity shortfalls are met through short-term annual capacity market purchases.

8.6 Concluding Comments on Candidate Portfolios

A total of 14 Candidate Portfolios were developed in Step 3 of the IRP process. The resulting expansion plans are described above. An initial review of all Candidate Portfolios showed that a majority of the Candidate Portfolios revealed similar patterns and portfolio additions, specifically in the near-term period to address the retirement of the Rockport Plant. This includes a combination of solar, wind and hybrid resources as soon as they are available to replace the capacity need that exists when Rockport Unit 2 is no longer available beginning in 2024, along with CT capacity additions to replace Rockport Unit 1 retirement in 2028. The standouts for differences are regarding the Rockport 1 retirement sensitivities whereas Rockport Unit 1 – 2024 and Rockport Unit 1 – 2025 portfolios include early additions of standalone storage in order to replace the Rockport capacity as a CT addition is not available until 2026 due to construction timing. Regarding the post 2030 differences, Rapid Technology Advancement and Enhanced Regulation portfolios contain a large amount of wind and solar additions, due to the economic benefits that are unique to these scenarios, as a replacement for Cook Unit 1 and Unit 2 retirements that are assumed for modeling purposes. The results of the portfolio selection and key performance metrics were presented in Stakeholder meeting 3B. During this process, and in subsequent discussion, it was decided that all 14 portfolios would progress to Step 4 as Candidate Portfolios for further analysis.

The development of Candidate Portfolios does not include the evaluation of comparative metrics that could be used to assess which, if any, Candidate Portfolios are better suited to meet I&M's objectives. Rather, KPI's were developed in Step 3 for each Candidate Portfolio to determine whether or not they met reliability and risk requirements. Most portfolios met these requirements with sufficient capacity and limitations on imports and exports of energy. However, several portfolios showed the potential to result in large exports of energy which could present an economic risk to those Candidate Portfolios. Comparative metrics to evaluate the relative cost and performance characteristics of each of the Candidate Portfolios were developed in Step 4, as discussed below.

9 Portfolio Performance and Preferred Portfolio Selection

9.1 Evaluation of Portfolio Performance

A total of 14 Candidate Portfolios were developed from Step 3 of the IRP process. The resulting expansion plans are described in Section 8. The results of the portfolio selection and KPIs were presented in Stakeholder meeting 3B for all the portfolios that were developed at that time. During this process, and in subsequent discussions, it was determined that all 14 portfolios would be progressed to Step 4 as Candidate Portfolios for further analysis. Two additional portfolios were constructed subsequently and will be discussed in this section. These include the Preferred Portfolio and then the OVEC 2030 Portfolio Sensitivity.

9.2 Stochastic Risk Assessment

Once the 14 Candidate Portfolios were identified, the remaining steps were to conduct the stochastic risk assessment and generate the comparative metrics used in the Balanced Scorecard. A stochastic risk analysis approach was utilized to provide a holistic assessment of how the 14 portfolios performed under a range of market conditions.

Key information is provided in the metrics in the Balanced Scorecard below. A major benefit of the Balanced Scorecard is that it provides I&M and Stakeholders clear insight into the differences between cost, cost uncertainty, sustainability, market reliance and resource diversity.

The specific metrics used to inform the Balanced Scorecard are displayed in Table 21 below. A full discussion is included in Section 2.

Table 21. IRP Objectives and Metrics

Objective Category	Objective	Metric
Affordability	Affordability	20-Year NPV Cost to Serve Load 10-Year NPV Cost to Serve Load
	Rate Stability	95th percentile value of NPV Cost to Serve Load Difference Between Mean and 95th Percentile 5 Year Net Rate Increase CAGR (2025-2029) Capital Investment Through 2028
	Market Risk Minimization	20-Year Average of Purchases as a % of Load 20-Year Average of Sales as a % of Load
Sustainability	Sustainability	% Reduction of CO_2 (2005-2041)
Reliability and Resource Diversification	Reliability	Surplus Reserve Margin above FPR Requirement
	Resource Diversity	Number of Unique Generators (2041) Number of Unique Fuel Types (2041)

A summary of how the 14 Candidate Portfolios described in Section 8 performed against key metrics is provided in the Table 22 below:

Table 22. Candidate Portfolio Balanced Abbreviated Scorecard

Candidate Portfolio	20-Year NPV CTSL	10-Year NPV CTSL	95th Percentile Value of NPV CTSL	Reduction of CO_2 (2005-2041)	Purchases as a % of Load (2021-2041)	Sales as a % of Load (2021-2041)	Surplus Reserve Margin (2041)
Reference Case (Original)	$7.30 B	$4.28 B	$8.55 B	75.9%	6.4%	25.9%	8.6%
Rockport 1 2024	$7.30 B	$4.29 B	$8.58 B	76.0%	6.3%	25.0%	5.8%
Rockport 1 2025	$7.49 B	$4.39 B	$8.76 B	77.5%	6.1%	25.9%	6.3%
Rockport 1 2026	$7.27 B	$4.27 B	$8.54 B	76.6%	6.3%	26.0%	1.2%
Cook 2050+	$6.57 B	$4.29 B	$7.90 B	97.8%	2.7%	37.5%	7.5%
Cook 2050+ and No Gas	$7.03 B	$4.42 B	$8.36 B	99.4%	2.8%	35.3%	1.6%
Reference with Expanded Build Limits	$7.93 B	$4.57 B	$9.23 B	81.0%	4.1%	38.4%	3.2%
Reference’	$6.98 B	$4.06 B	$8.26 B	76.4%	6.2%	26.3%	2.5%
Reference with No Renewable Limits	$10.49 B	$6.10 B	$12.13 B	96.2%	2.7%	96.3%	4.9%
Rapid Technology Advancement	$7.50 B	$4.26 B	$8.81 B	94.4%	3.6%	36.8%	5.1%
Enhanced Regulation	$7.49 B	$4.16 B	$8.81 B	94.3%	3.6%	37.2%	4.0%
Rockport 1 2024 NTG	$7.43 B	$4.37 B	$8.70 B	76.7%	6.0%	25.4%	7.0%
Rockport 1 2026 NTG	$7.26 B	$4.29 B	$8.53 B	77.3%	6.0%	26.2%	1.7%
Rapid Technology Advancement NTG	$7.28 B	$4.19 B	$8.85 B	93.5%	4.0%	35.3%	1.4%

I&M conducted a review of the Candidate Portfolio Balanced Scorecard shown in Table 22, the comparative metrics for each Candidate Portfolio, and refined the list of Candidate Portfolios to those Candidate Portfolios that represented viable strategic options for I&M. Table 23 shows the rationale for the eliminated Candidate Portfolios and those that were refined or maintained for further study.

Table 23. Candidate Portfolios Analysis and Screening

Portfolio Name, Revised	Action	Rational
Reference Case (Original)	Refined	Used for initial comparison
Rockport 1 2024	Inform	Evaluate Early Rockport Retirement, Minimal Lead Time for New Resources
Rockport 1 2025	Inform	Evaluate Early Rockport Retirement, Minimal Lead Time for New Resources
Rockport 1 2026	Compare	Evaluate Early Rockport Retirement
Cook 2050+[1]	Compare	Optionality to Maintain Nuclear Resources, Sustainability Goals
Cook 2050+ and No Gas	Compare	Optionality to Maintain Nuclear Resources, Sustainability Goals
Expanded Build Limits	Inform	Evaluate Build Limits, High Exports and Costs
Reference'	Evaluate	Manage Export Limits
No Build Limits	Inform	No Build Limits, High Exports and High Costs
Rapid Technology Advancement	Compare	Scenario Results
Enhanced Regulation	Compare	Scenario Results
Rockport 1 2024 N2G	Inform	Evaluate Alternative Treatment of Energy Efficiency Resources
Rockport 1 2026 N2G	Inform	Evaluate Alternative Treatment of Energy Efficiency Resources
Rapid Technology Advancement N2G	Inform	Evaluate Alternative Treatment of Energy Efficiency Resources

As shown in Table 23, the Reference Case (Original) was refined and replaced by the Reference' Candidate Portfolio, as described in Section 8.3.7. The Rockport 2024 and Rockport 2025 Candidate Portfolios, which considered the early retirement of Rockport Unit 1, were screened out due a lack of time (i) for a reasonable transition and (ii) to replace the Rockport Unit 1 capacity and energy needed to maintain system reliability and resource adequacy for I&M's customers. The Rockport 2026 Portfolio was maintained for comparison purposes. However, based on the time needed to conduct a competitive procurement process, secure all required permits, obtain regulatory approval, and construct the level of resource additions that would be required to replace both Rockport Units 1 and 2 in this condensed timeframe, the Company determined that there is likely insufficient time for a reasonable and practical transition. Additionally, the Rockport early retirement

Candidate Portfolios would not allow sufficient time for I&M to work with the local communities, employees and other stakeholders impacted by the retirement of Rockport.[28]

The Expanded Build Limits portfolio and the No Build Limits portfolio, used to evaluate the cost and performance implications of portfolio limitations on new capacity additions, were screened out due to their high energy exports, exposure to market risk, and costs. Energy exports that exceed acceptable thresholds can produce greater economic risks due to the uncertainty of future energy spot market prices and also did not meet I&M's objectives around managing capacity and energy length above its projected load requirements. Annual build limits were removed for the Reference with No Renewable Limits Candidate Portfolio, which as shown in Table 22, results in Sales as a Percent of Load averaging 96.3% over the analysis period. The three Net-to-Gross portfolios, Rockport 1 2024 N2G, Rockport 1 2026 N2G, and Rapid Technology Advancement N2G, were screened out as they were used to evaluate an alternative method of modeling new energy efficiency resources related to the Settlement Agreement in IURC Cause No. 45546. While the Company plans to study and test potential modifications needed to model NTG EE bundles savings in the IRP modeling construct in future IRP's, this approach includes and monetizes energy efficiency savings that already are included in the Company's load forecast described in Section 5.6.2 and further discussed in section 7.8.1 used for this IRP.

Table 24 shows the resulting focused Candidate Portfolios complete Balanced Scorecard metrics used to inform the development of the Preferred Portfolio.

Table 24. Focused Candidate Portfolio Balanced Scorecard

Portfolio	20-Year NPV CTSL	10-Year NPV CTSL	95th Percentile Value of NPV CTSL	Difference Btw. Mean and 95th Percentile	5 Year Net Rate Increase CAGR (2025-2029)	Capital Investment Through 2028	% Reduction of CO2 (2005-2041)	Purchases as a % of Load (2021-2041)	Sales as a % of Load (2021-2041)	Surplus Reserve Margin (2041)	# of Unique Generators (2041)
Reference'	$6.98 B	$4.06 B	$8.26 B	18.3%	1.3%	$5.52 B	76.4%	6.2%	26.3%	2.5%	61
Rockport 1 2026	$7.27 B	$4.27 B	$8.54 B	17.5%	1.3%	$5.56 B	76.6%	6.3%	26.0%	1.2%	58
Cook 2050+	$6.57 B	$4.29 B	$7.90 B	21.0%	1.5%	$5.69 B	97.8%	2.7%	37.5%	7.5%	55
Cook 2050+ and No Gas	$7.03 B	$4.42 B	$8.26 B	20.4%	1.5%	$5.40 B	99.4%	2.8%	35.3%	1.6%	68
Rapid Technology Adv.	$7.50 B	$4.26 B	$8.81 B	17.5%	0.0%	$3.8 B	94.4%	3.6%	36.8%	5.1%	101
Enhanced Regulation	$7.49 B	$4.16 B	$8.81 B	17.6%	1.50%	$5.69 B	94.3%	3.6%	37.2%	4.0%	100

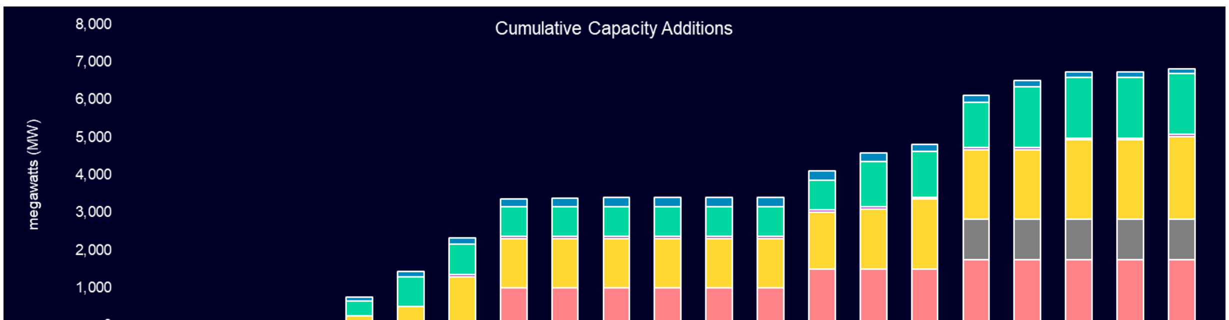
[28] Refer to AEP's commitment to a Just Transition at AEPs-Climate-Impact-Analysis-2021.pdf (aepsustainability.com)

Based on the results of the IRP Step 4 analysis of the Candidate Portfolios as shown in Table 24, the Reference' Candidate Portfolio was selected as the basis for the development of the Preferred Portfolio. The selection of the Reference' Candidate Portfolio resulted in the 2nd lowest 20-Year NPV CTSL and the lowest 10-Year NPV CTSL (net present value of the cost to serve load) metrics and with respect to the other metrics was very similar to or better than the Rockport 2026, Rapid Technology Advancement and Enhanced Regulation portfolios. Only the Cook 2050+ portfolio has a lower 20-year NPV CTSL metric. The Cook 2050+ portfolios were used exclusively to inform the development of the Preferred Portfolio. These portfolios do not include the estimated capital costs that would be necessary to support extending the lives of the Cook units, thus impacting the Affordability metrics in the Balanced Scorecard and as shown in Table 24. However, the Cook 2050+ portfolios do provide valuable strategic insights related to sustainability, reliability and resource adequacy. In addition, the Reference' Candidate Portfolio results in a forecasted CAGR that is in line with all of the other portfolios shown in Table 24 with the exception of the Rapid Technology candidate portfolio. However, the Rapid Technology Advancement candidate portfolio assumes, as described in Section 3, a 35% reduction in wind, solar, storage, energy efficiency and demand response technology costs. With very similar capacity additions as the Reference' Portfolio, this scenario was insightful to the benefits of low cost renewable resources if there is a future rapid decline in renewable technology costs. For purposes of developing the Preferred Portfolio, the Company is assuming the more conservative cost assumptions included in the Preferred Portfolio and informed by the RFP's discussed in sections 6.2 and 6.3. Furthermore, one of the Company's priorities is to manage the levels of Average Sales as a Percentage of Load across the analysis period, as shown in Table 24. While the Reference' Portfolio has one of the lower sales percentages of the Portfolios included in Table 24, the Company wanted to further address this "energy length" in the development of the Preferred Portfolio. Stakeholders also expressed concern regarding the potential for future energy length, specifically with respect to the potential future impacts of an industry wide transition to renewable energy resources. The concern is that while individual utility assumptions regarding future market sales may be reasonable, when evaluated in aggregate with other utilities' plans, there could become a market surplus that would reduce the opportunity for future market sales. If this situation were to occur, it may result in less market sales revenues than forecasted.

9.3 Preferred Portfolio Overview

The Preferred Portfolio was informed by the results of the many Candidate Portfolios discussed in Section 8. It represents a balanced plan that supports I&M's IRP objectives and provides a planning basis for the Company's near-term plan, 2022 – 2028, and long-term-indicative plan, 2029 – 2041. The Preferred Portfolio also maintains optionality for the Company's continued consideration for the life extension of the Cook nuclear units beginning in 2034, by including the same resource types in the near-term plan, but reducing the amounts to manage the Sales as a Percentage of Load metric over the long-term. The Preferred Portfolio was derived from the Reference' Candidate Portfolio with adjustments to resource selections to reduce risks around near-term capital requirements, project execution, reserve margin and energy position surplus influence on portfolio costs in order to best align with the Company's overall objectives and metrics. Resource additions in the Preferred Portfolio are shown in Figure 51. Table 20 shows the comparison of resource additions for all Portfolios from a near-term (2022 to 2028) and long-term (2029 to 2041) perspective. Appendix C has key information for each Portfolio, and Appendix C-19 and C-20 show total resources by year and total capacity relative to the Company's forecasted load obligation. Key additions through 2041 include:

- 2,200 MW of Solar Resources
- 1,600 MW of Wind Resources
- 60 MW of Storage Resources paired with Solar Resources
- 247 MW of peak EE resources in 2033
- 2,820 MW of Dispatchable Gas Resources



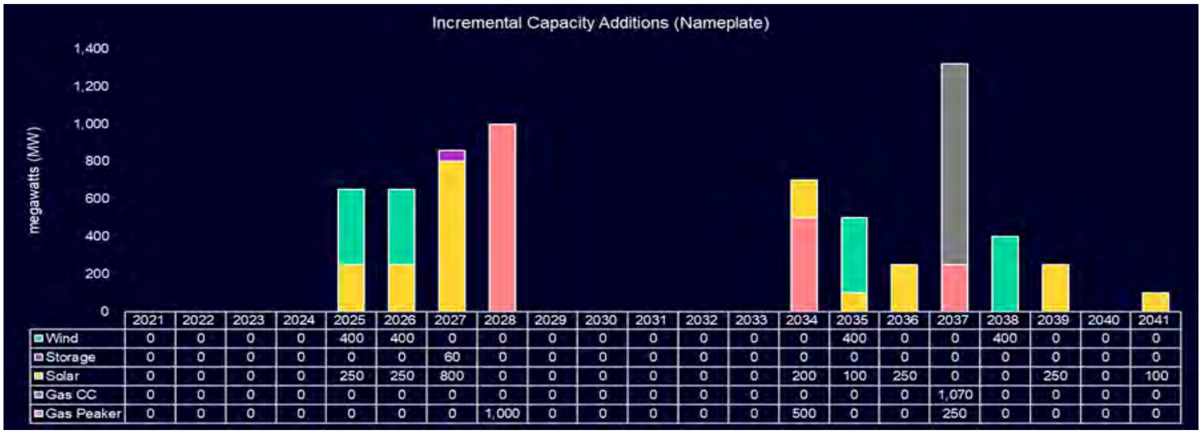
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	112	144	172	189	210	233	234	241	247	235	213	197	182	168	157	149	124
Wind	0	0	0	0	400	800	800	800	800	800	800	800	800	800	1,200	1,200	1,200	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Solar	0	0	0	0	250	500	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,500	1,600	1,850	1,850	1,850	2,100	2,100	2,200
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,500	1,500	1,500	1,750	1,750	1,750	1,750	1,750
Total	0	0	50	96	762	1,444	2,332	3,349	3,370	3,393	3,394	3,401	3,407	4,095	4,573	4,807	6,112	6,498	6,737	6,729	6,804

Figure 51. Preferred Portfolio Capacity Expansion Plan

The Balance Scorecard metrics are shown in Table 25 below and are further discussed in Section 9.4

Table 25. Preferred Portfolio Scorecard Metrics

Portfolio	20-Year NPV CTSL	10-Year NPV CTSL	95th Percentile Value of NPV CTSL	Difference Btw. Mean and 95th Percentile	5 Year Net Rate Increase CAGR (2025-2029)	Capital Investment Through 2028	% Reduction of CO2e (2005-2041)	Purchases as a % of Load (2021-2041)	Sales as a % of Load (2021-2041)	Surplus Reserve Margin (2041)	# of Unique Generators (2041)
Preferred Portfolio	$6.76 B	$3.89 B	$8.10 B	19.6%	1.40%	$3.83 B	76.2%	7.20%	19.80%	4.7%	66



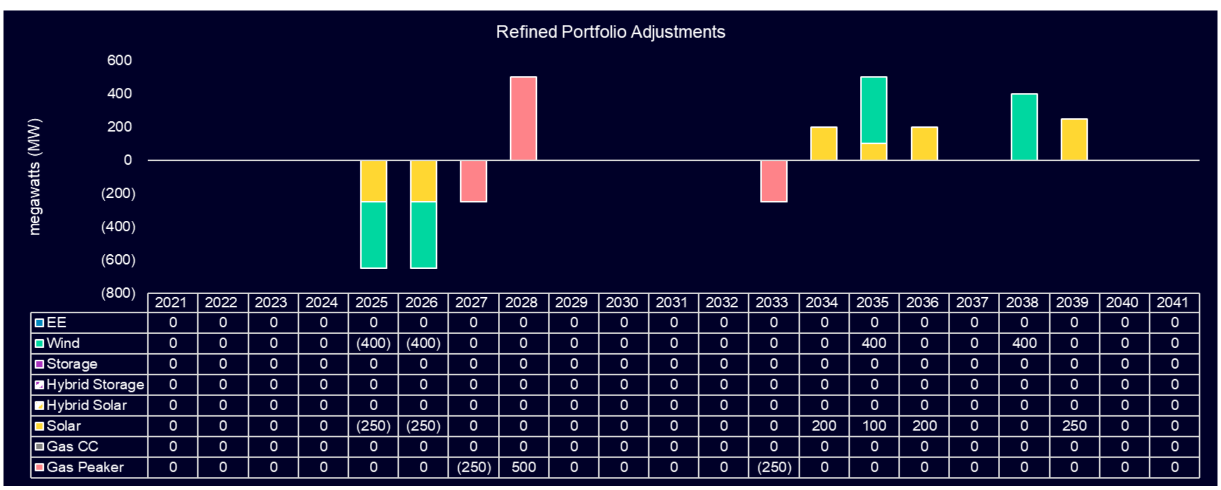
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Wind	0	0	0	0	400	400	0	0	0	0	0	0	0	0	400	0	0	400	0	0	0
Storage	0	0	0	0	0	0	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	250	250	800	0	0	0	0	0	0	200	100	250	0	0	250	0	100
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	1,000	0	0	0	0	0	500	0	0	250	0	0	0	0

Figure 52. Preferred Portfolio Incremental Capacity Additions (UCAP)

The Preferred Portfolio was informed from all the Candidate Portfolios and derived from the Reference' Portfolio. The adjustments to the Reference' Portfolio included:

- In 2025-2026, renewable additions were reduced by 50%, these additions were shifted out to later years
- 2027 and 2033 gas peaker additions were combined and added in 2028, for a total of 1,000 MW
- Includes an additional 250 MW of solar resources in long-term

Each of these adjustments is discussed further below.



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	(400)	(400)	0	0	0	0	0	0	0	0	400	0	0	400	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	(250)	(250)	0	0	0	0	0	0	0	200	100	200	0	0	250	0	0
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	(250)	500	0	0	0	0	(250)	0	0	0	0	0	0	0	0

Figure 53. Preferred Portfolio - Adjustments to Reference'

9.4 Path to the Preferred Portfolio

I&M's Preferred Portfolio results from modifications to the optimized Reference' portfolio, which was one of the best performing portfolios in the Balanced Scorecard. Resource type additions in the

Preferred Portfolio are similar to the Cook 2050+ Portfolio in the near-term through 2028, while managing near-term capacity and energy length positions.

More specifically, the Company evaluated the resource additions in the Cook 2050+ Portfolio relative to the Reference' Portfolio, assessing the various metrics discussed in Section 8. The Reference' Portfolio included a high amount of renewable resources in the near term to take advantage of Federal renewable tax credits, in particular wind resources, however that impacted the Company's energy position, imposing additional market risk through forecasted energy margins, as reflected in the Sales as a Percentage of Load metric in the Balanced Scorecard and Exhibit C-21. This sales length begins to grow in 2025 as the model adds low-cost wind and solar resources up to the Company constraints, discussed in Section 7.6.5.1. Due to this and other considerations, the Company reduced the solar and wind resource additions in 2025 and 2026 by 50%, which reduced the forecasted energy length in 2027 by approximately a third, down to 29% and is reflected in the Preferred Portfolio, while meeting its PJM capacity obligation.

Additionally, this modification reduces the Preferred Portfolio's Capital Investment through 2028 to $3.83 B, whereas the Reference' Portfolio has a $5.52 B capital investment need through the same time period. If similar resource price conditions occurred as modeled in the RTA Portfolio, the Preferred Portfolio would realize similar benefits proportional to the resources selected. As an example, a 35% reduction in resource costs would reduce the Preferred Portfolio resource costs by approximately $1 billion. The reduced amount of renewable additions may also reduce the Company's implementation risk that otherwise would be associated with adding the large amounts of solar and wind resources called for in the Reference' Portfolio.

Table 26 below shows the forecasted impacts of each rate component on the metric in 2029. As shown on line 6, Total Gross Revenue Requirement, the Preferred Portfolio has significantly lower costs than the Reference' portfolio. The Net Cost of Service Impact on line 8 shows the Reference' Portfolio has the lowest Net Cost of Service Impact, which directly correlates to the calculation of Net Retail Rate Impact. However, the clear drivers of the lower Net Cost of Service Impact is the Grossed up PTC/ITC credits shown on line 5, which assumes efficient realization of federal renewable tax credits as described in section 7.6.4, and the forecasted value of energy margins from market sales, shown on line 7. The Reference' Portfolio has a forecasted benefit of $409M while the Preferred Portfolio has a forecasted benefit of $269M, a difference of $140M in one year. This is an example of the risks the Company is managing in the development of the Preferred Portfolio by reducing the Solar and Wind resources as compared to those that were included in the Reference' portfolio.

Table 26: Retail Rate Impact Comparison

		2029 Single year Cost of Service Components and Net CAGR components	
		Preferred Portfolio	Reference'
Line			
	Ratemaking Revenue Requirement - 100% owned		
1	Pre-Tax Return on Rate Base	$249	$354
2	Depreciation Expense	$118	$170
3	Fixed O&M	$126	$169
4	Subtotal, prior to PTC/ITC	$493	$693
5	Less: Grossed Up PTC/ITC	($72)	($142)
6	Total Gross Revenue Requirement	$421	$552
7	Less: Variable Energy Margin (Revenue-Fuel-VOM)	($269)	($409)
8	Net Cost of Service Impact	$151	$143
9			
10	Year over year Gross COS change	($6)	($11)
11	Year over year Net COS change	($12)	($18)
12			
13		**5 Year CAGR end year 2029**	
14		Net	Net
15	2020 Base Year Retail & FERC Revenues	$2,181	$2,181
16	2029 Projection, New Resource Cost of Service	$151	$143
17	Total 2029 Net Cost of Service	$2,332	$2,324
18			
19	Gross / Net % Cumulative Increase over 2020 Base year	6.9%	6.6%
20	Net CAGR 2025-2029	1.40%	1.30%
21			
22	2025-2028 Cumulative Capital Investment	3.83	5.52

Furthermore, the Company identified that the introduction of a 250 MW CT in 2027 in the Reference' Portfolio could be delayed by a year and combined with the 2028 CT's. In the Preferred Portfolio, the Company chose to delay the introduction of this CT in 2027 and at the same time pull forward a plan to introduce a CT in 2033 for a total of 1,000 MW of CT's in 2028. The results of this modification to the Reference' Portfolio's impact on Capacity Surplus can be seen in Exhibit C-20 by year. From 2025 through 2037 the Preferred Portfolio has a lower Capacity Surplus than the Reference' Portfolio. The combination of these resources is used to meet capacity needs in 2028 with the planned retirement of the Rockport Unit 1. While the Preferred Portfolio includes 1,000 MW of CT resources in 2028, the Company will conduct future competitive procurement processes to determine the optimal resource selections.

With these adjustments, the Company is able to retain the optionality for decisions related to potential license extensions at the Cook nuclear plant.

9.5 Description of the Preferred Portfolio

Figure 54 illustrates I&M's UCAP capacity position for the Preferred Portfolio and the PJM capacity obligation. In addition to the existing resources, nameplate capacities of new supply-side resources in the Preferred Portfolio includes 1,600 MW of wind resources selected through 2038, 1,900 MW of stand-alone solar resources selected through 2041, the selection of hybrid paired solar + storage resources in 2027 of 60 MW storage / 300 MW Solar in 2027, 1,070 MW of Gas CC selected in 2037, and 1,750 MW of Gas CT resources through 2040. Resource additions built through 2028 are sufficient from a capacity and energy perspective to address needs in light of the retirement of the Rockport Units. In the Preferred Portfolio, Rockport Unit 1 and Unit 2 operations continue through 2028 and 2024, respectively. Cook Unit 1 and 2 operations are assumed for IRP modeling purposes only to continue through 2034 and 2037, respectively.

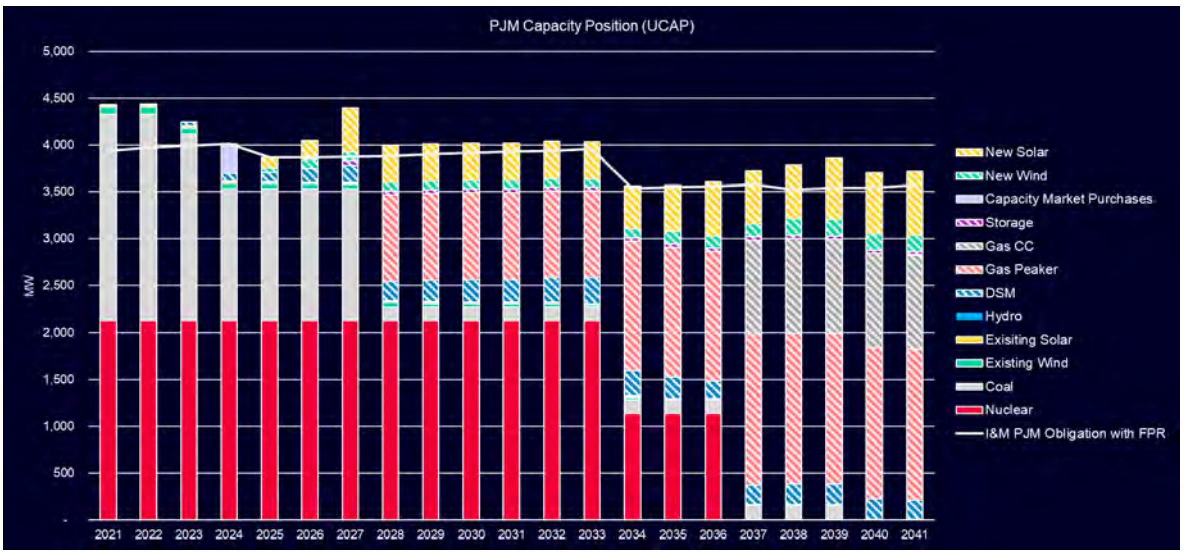


Figure 54: I&M's Preferred Portfolio PJM Capacity Position (MW-UCAP) New and Existing Resources

In addition to the supply-side resources, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 247 MW in 2033. The energy efficiency programs are spread across three vintages (2023-2025, 2026-2028 and 2029-2040) and across eight C&I bundles and five Residential bundles. The Preferred Portfolio selected all C&I Block 1, C&I Block 3, and C&I Block 8 bundles, as well as substantial quantities of C&I Block 7, Residential Block 2, Residential Block 3 and Residential Block 7. The Preferred Portfolio also has small quantities of C&I Block 2, C&I Block 4, C&I Block 5 and C&I Block 6. In addition, low-income energy efficiency and EE programs included in existing filings (i.e., MI 2021) are included in all periods. The optimal dispatch of demand response is selected and is informed through the MPS and includes incremental resources of 121 MW. The only short-term capacity deficit relative to the PJM minimum reserve requirement is observed in 2024 and is currently forecasted to be ~314 MW as the portfolio transitions from Rockport Unit 2 to a portfolio with more renewable resources. Short term capacity needs are subject to further adjustments prior to the PJM Delivery Year based on evolving load forecasts and unit performance.

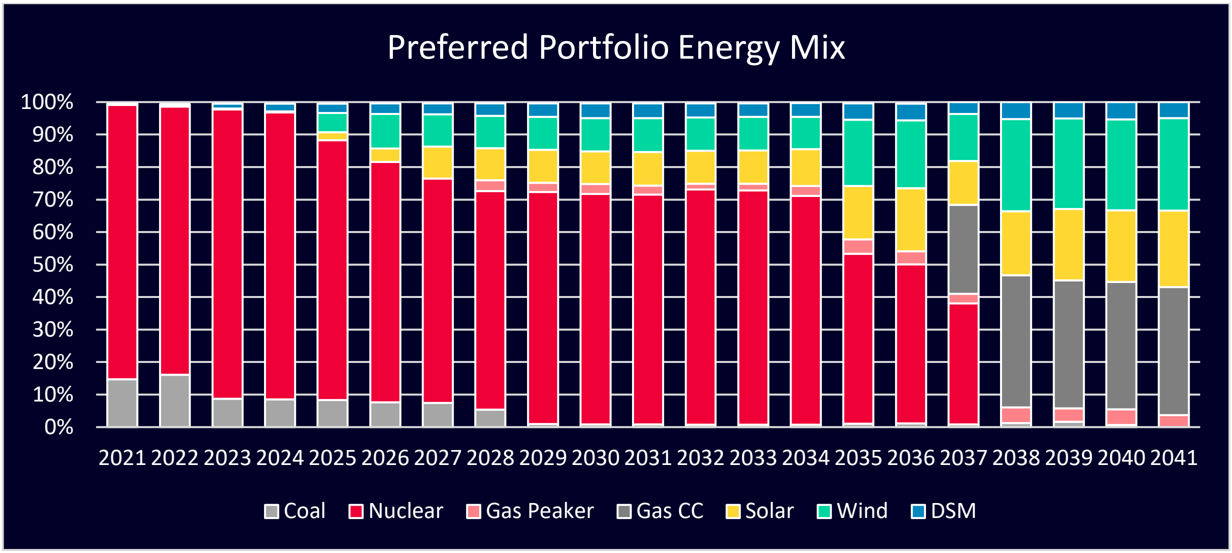


Figure 55: Preferred Portfolio Energy Mix

The forecasted energy mix by resource type contribution in the Preferred Portfolio over the planning period is illustrated in Figure 55. From an energy perspective, the Preferred Portfolio resources include the addition of energy rich renewable resources and DSM resources that serve to somewhat mitigate future risks related to fuel price uncertainty and potential carbon emission prices. Additionally, these resources include incremental dispatchable generating resources (CT) to support resource adequacy and reliability during the periods when renewable resources are not providing energy to meet the Company's load obligation.

The Preferred Portfolio performs well across a range of metrics that were used in the Balanced Scorecard. The Preferred Portfolio performs very well in absolute terms and relative to other Candidate Portfolios and is the lowest cost portfolio. The Preferred Portfolio provides several additional benefits to I&M customers and Stakeholders, including:

Affordability and Rate Stability:

- The Preferred Portfolio is among the lowest reasonable cost portfolios measured on both a 20-year and 10-year cost to serve load metric. The only comparable portfolios are the Cook 2050+ life extension portfolios, which do not include consideration of the capital investments required to extend the life of those facilities (will be evaluated further in future IRPs).
- The Preferred Portfolio has one of the lowest absolute values for the 95th percentile value of NPV cost to serve load. All portfolios share a similar upside risk. This translates into having one of the lowest risk of increases in cost across the portfolios.
- Resource type additions in the Preferred Portfolio are similar through 2028 as the portfolios modeled considered Cook license extensions (Cook 2050+) resulting in a "no regrets" position for the next several years.
- The Preferred Portfolio includes dispatchable resources that can enhance opportunities for wholesale sales without overexposure to market risks.

- The Preferred Portfolio takes advantage of existing tax incentives for new wind, solar and hybrid solar resources.

Market Risk

- The Preferred Portfolio mitigates overreliance on market purchases and sales for capacity and energy throughout the forecast horizon.
- The Preferred Portfolio requires market purchases for capacity in 2024 to account for Rockport unit 2 settlement requirements.
- Market purchases for energy are reasonable and do not overexpose I&M to the spot energy market, with the preferred portfolio averaging 7.2% over the forecast horizon. Additionally, market sales for energy are reasonable and do not overexpose I&M to the spot energy market, with the preferred portfolio averaging 19.8% over the forecast horizon.
- The Preferred Portfolio results in small amounts of surplus capacity over the forecast period.
- The Preferred Portfolio avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

Sustainability:

- The Preferred Portfolio leads to a lower carbon future, achieving 76% reduction from 2005 levels by 2041 when including equivalent emissions for spot market purchases. Excluding spot market purchase emissions estimates, the Preferred Portfolio realizes CO2 emissions reductions of 82%.
- The Preferred Portfolio includes a substantial amount of renewable resources as it continues to transform its fleet.
- The Preferred Portfolio maintains the optionality for the Cook License Extensions which maintains the opportunity to extend the operations a significant emission-free resource.
- The Preferred Portfolio provides potential opportunities for natural gas conversion to hydrogen fuel later in the planning period.
- The Preferred Portfolio significantly reduces the reliance on coal fired generation.

Reliability and Resource Diversity:

- The Preferred Portfolio includes additions that when added to Company's current resources, provides a more diversified portfolio of supply-side and demand-side resources that will allow the Company to optimize the use of each resource type to ensure the reliable supply of electricity.
- The CT resources provide flexible, fast ramping capabilities and can help mitigate risks brought on by the intermittent renewable resource additions.

9.6 Affordability

Affordability is an important objective in the Balanced Scorecard and is measured as a component of the stochastic analysis. The metrics to capture the affordability objective include the 20-year Net Present Value of Cost to Serve Load and a 10-year Net Present Value of Cost to Serve Load. The values in the Balanced Scorecard represent the stochastic mean (average) of the 200 dispatch simulations of the portfolio under varying market conditions. Within each stochastic run, the model outputs the annual cost of each component to calculate total portfolio cost, including fuel costs, emission costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenue, energy import costs, and capacity market purchase costs. The components of the cost to serve load are summed over the forecast horizon and discounted by I&Ms weighted average cost of capital of 7.19% to arrive at the Net Present Value Cost to Serve Load. A lower Net Present Value Cost to Serve Load translates into a lower expected cost of energy for customers.

The Preferred Portfolio is the least cost portfolio across all other Candidate Portfolios, with the 20-year Net Present Value Cost to Serve Load of $6.76 B and a 10-year Net Present Value Cost to Serve Load of $3.89 B. The Net Present Value Cost to Serve Load of the preferred portfolio is over 6% less than the reference portfolio and over 2% less than the Reference' portfolio.

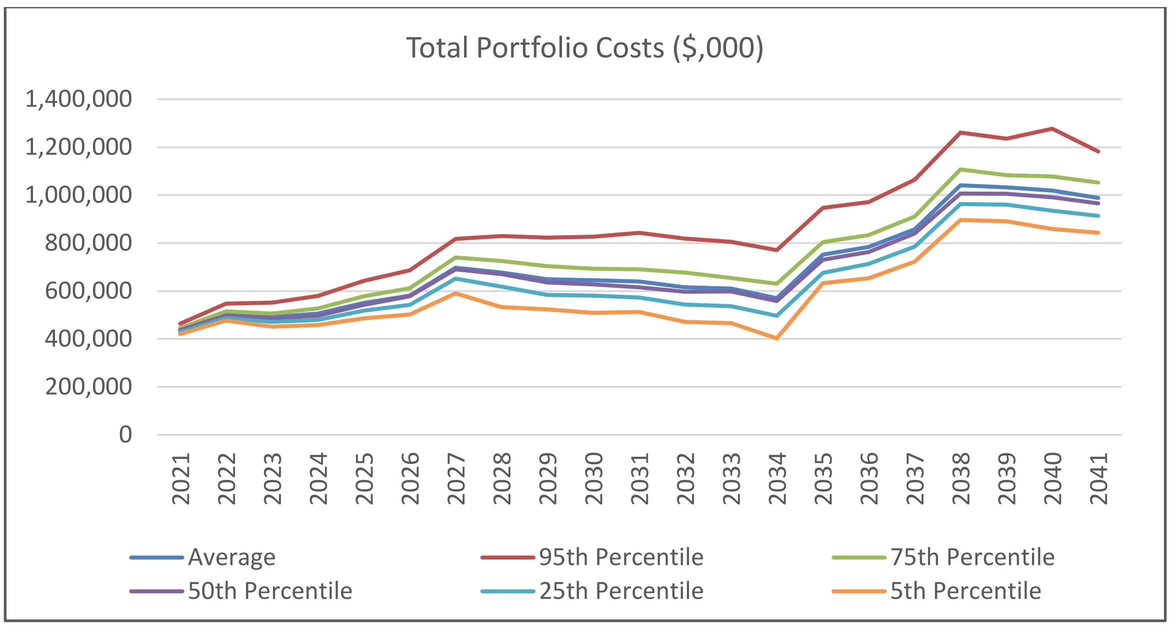


Figure 56. Total Preferred Portfolio Cost P-Bands, Preferred Portfolio

9.7 Rate Stability

The Rate Stability objective is measured through two approaches. The first approach is measured in a similar way to the Affordability objective, using the 20-year and 10-year Net Present Value Cost to Serve Load from the stochastic analysis. However, the objective provides a measure of the 95th percentile of the Net Present Value Cost to Serve Load to identify an upper boundary of portfolio costs across the 200 iterations. The 95th percentile can be considered a reasonable upper boundary or worst-case perspective that the portfolio could experience. The 95th percentile can be interpreted to say that there is a 95% chance that total portfolio costs as measured by the Net Present Value Cost to Serve Load will be at or below this measure. As a result, the risk of the total portfolio costs over the study period can be quantified allowing the comparison of risk. In addition to the 95th percentile, a 5-year CAGR of the net retail rate impact was calculated. The 5-yr CAGR metric provides near term insight to customer affordability and rate impacts of the resource additions in a given portfolio. The CAGR was calculated using a traditional, non-levelized, calculation of the annual cost of service and the change in revenue requirement for the period of 2025-2029 when new resources are added.

The Preferred Portfolio performed well in the rate stability category. The 95th percentile of the 20-year Net Present Value Cost to Serve Load was determined to be $8.1 B, which is the 2nd lowest number when compared to other portfolios with only the Cook 2050+ portfolio as lower although this does not include the estimated capital costs that would be necessary to support extending the lives of the Cook units. In terms of the impact to retail rates, the Preferred Portfolio on a CAGR basis performed in-line with the other Candidate Portfolios excluding the technology cost assumptions used in the RTA Portfolio. The Preferred Portfolio out-performed all others when considering the amount of dollars required of the early years of the plan, measured through capital intensity. The Preferred Portfolio capital investment through 2028 totaled $3.83 B, which is much less when compared to the $5.69 B from the Reference portfolio or $5.52 B from the Reference' portfolio.

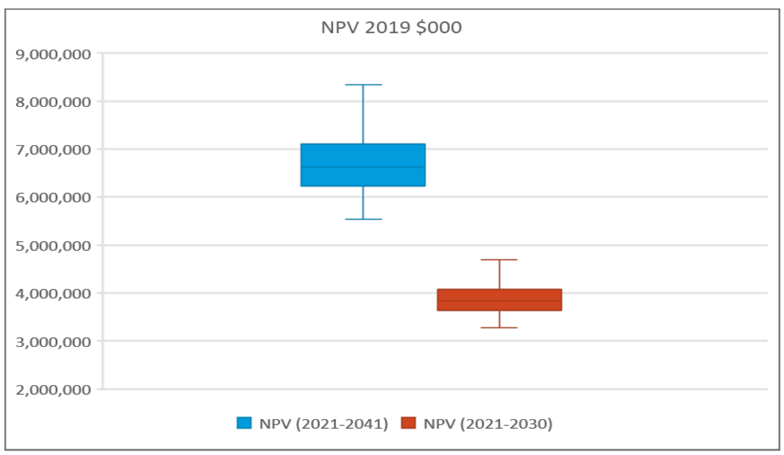


Figure 57. NPV of Cost to Serve Load, Preferred Portfolio

9.8 Sustainability

The Sustainability objective results are determined from the stochastic analysis and are estimated through direct GHG emissions of each generation type plus the impact from spot market purchases imported from the market. The metric is based on tons of carbon dioxide (CO_2) and includes direct emissions from I&M assets and estimated emissions from spot market purchases. The Reference Portfolio capacity expansion plan developed in Step 3 of the IRP process for PJM was used to estimate the average carbon content of the market purchases. CO2 emissions for each portfolio can be found in Exhibits C-1 through C16. A table for all portfolios of CO_2 emissions from direct I&M assets, total direct emissions including estimated market purchase emissions and estimated Lifecycle CO_2e emissions can be found in Exhibits C-24, C-25 and C-26.

The Preferred Portfolio performed consistent with all other portfolios. The Preferred Portfolio reduces annual CO_2 emissions when including equivalent emissions for spot market purchases by a total of

76% when measured against 2005 levels that did not include emissions assumptions from short-term and spot market purchases. Excluding spot market purchase emissions estimates, the Preferred Portfolio realizes CO_2 emissions reductions of 82%. This represents a significant decrease over the 20-year period. The Preferred Portfolio, however, does not reduce emissions from the portfolio as drastically as the sensitivities in which the Cook nuclear facility is considered to continue operations. These portfolios reduce CO_2 emissions by over 90% from 2005 levels. A major factor in developing the Preferred Portfolio was that it resulted in a consistent mix of resource additions prior to the period where a decision would need to be made to extend the lives pf the Cook Nuclear Plant. In the event the Cook Nuclear license were to be extended and the Company executed the Preferred Portfolio near-term plan through 2028, the Company would expect an annual CO_2 emissions reduction of 92% in 2041 when measured against levels from 2005. The Company's resource portfolio impact with potential licenses extension of the Cook Nuclear Plant units will be further examined in subsequent IRPs.

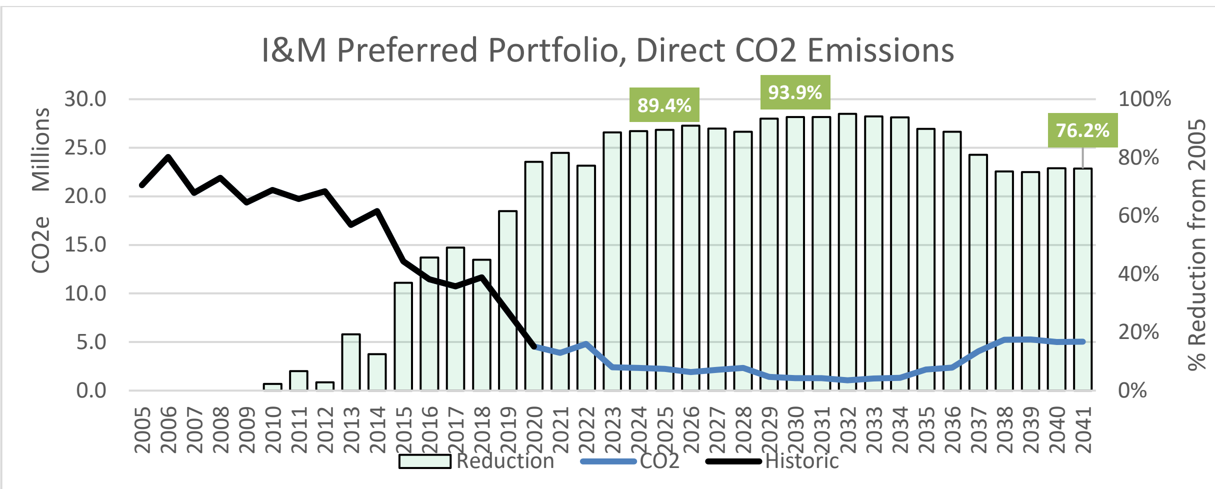


Figure 58. I&M Preferred Portfolio CO_2 Direct Emission

The Preferred Portfolio also results in dramatic reductions of SO_2 and NOx emissions as illustrated in Figure 59.

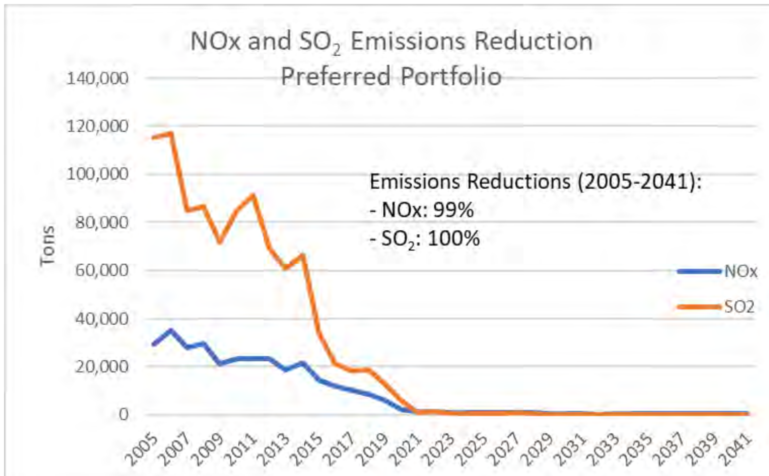


Figure 59: I&M Preferred Portfolio SO_2 and NOx Emissions Reductions

9.9 Market Risk Minimization

The Market Risk Minimization objective metrics includes a calculation of average annual energy sales and average annual energy purchases, each divided by the average annual load and expressed as a percentage over the 20-year time horizon. The metric is meant to capture a measure of reliance on market sales and/or purchases by the resulting portfolios. The greater the energy market purchases, or sales, required by a Candidate Portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the I&M fleet. Conversely, the greater the energy market sales by a Candidate Portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the I&M fleet. For the market risk minimization, heavy reliance on spot market purchases or sales could lead to an inflated value of a portfolio. With that said, it must be recognized that purchases and sales do not carry the same risk profile given that lesser spot sales reduce the energy cost offset while over-reliance on spot market purchases can potentially result in extremely high-cost power purchases during tight market conditions or even complete lack of supply.

The Preferred Portfolio performed well in terms of energy market risk minimization. The Preferred Portfolio averaged 7.2 percent of purchases as a percent of load and 19.8% of sales as a percent of load over the 2021 to 2041 timeframe.

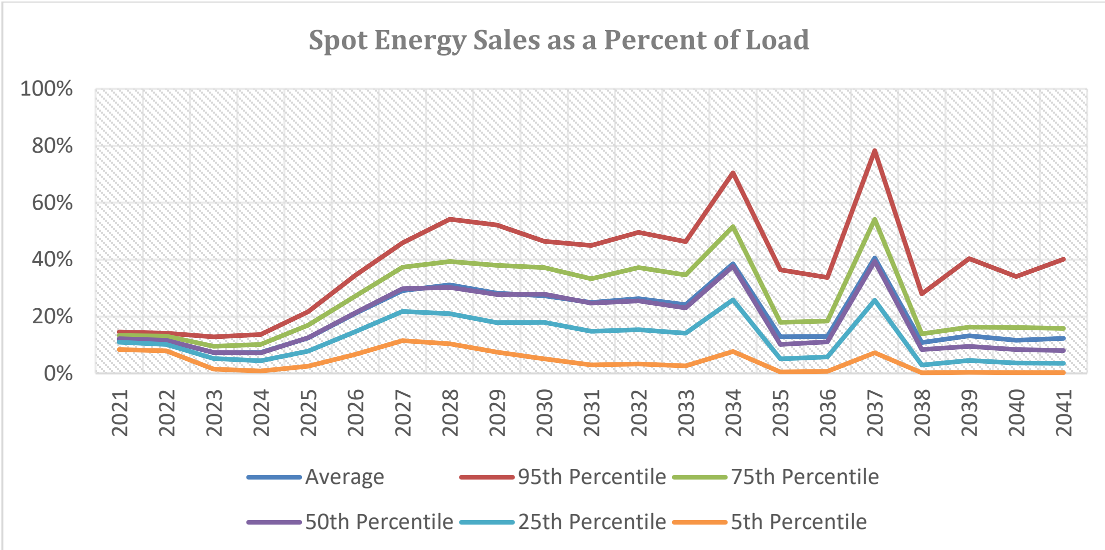


Figure 60. Spot Energy Sales as a Percent of Load

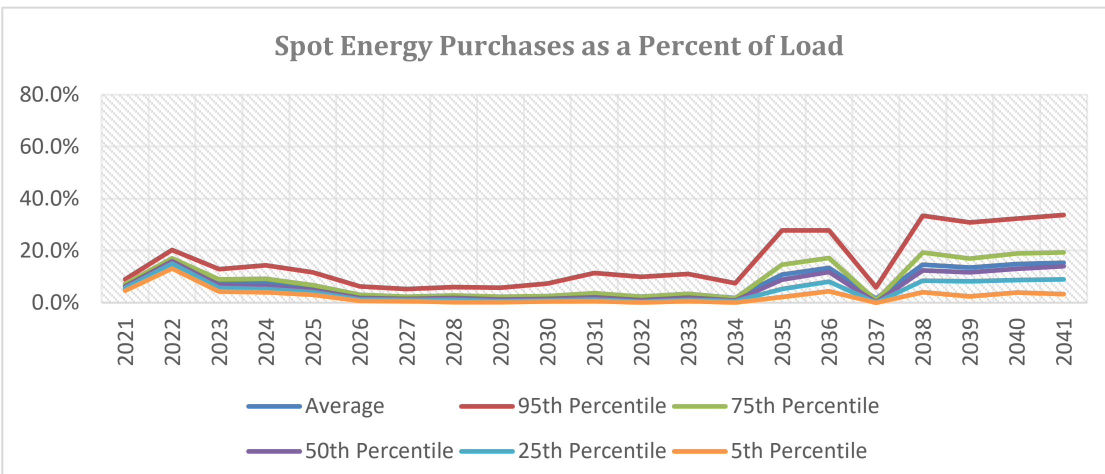


Figure 61. Spot Energy Purchases as a Percent of Load

9.10 Reliability and Resource Diversity

For the Reliability and Resource Diversity objective, the metrics used are the percent above or below I&M's PJM Reserve Margin Obligation (2041), Fuel Mix, and the Number of Unique Generators. The analysis includes the PJM Capacity Obligation, Reserve Margin and PJM's Guidance on Effective Load Carrying Capability (ELCC) for intermittent resource capacity analysis. The Preferred Portfolio had a surplus reserve margin of 4.7% in 2041, 66 unique generators in 2041 and eight fuel types. The retirement of the Rockport Plant by 2028 will result in approximately 50% of I&M's existing capacity resources. An important consideration in development of I&M's Preferred Portfolio was the resulting portfolios support of near-term reliability, resiliency and resource adequacy for I&M's customers

9.11 Supplemental Analysis

Once a Preferred Portfolio was selected, supplemental analysis was conducted to comply with Indiana and Michigan requirements related to Indiana Cause No. 45546 and Michigan Case No. U-20591. As a result, a scenario was modeled in which the OVEC Inter-Company Power Agreement (ICPA) was terminated early in 2030. It is important to note that the ICPA does not contain an early termination clause. This analysis was performed on the basis of certain assumptions that may not be achievable or consistent with the results. Specifically, the resources selected from the Preferred Portfolio were fixed and the OVEC contract termination date was modified to end in 2030. The portfolio was then optimized through the long-term capacity expansion module of AURORA to allow replacement resource options to be identified.

The OVEC 2030 Portfolio includes an identical mix of additions to the Preferred Portfolio except for the incremental addition of 250 MW of CT in 2030 to replace the OVEC capacity removed from the plan.

Because the model did not originally include the OVEC demand charges (non-energy charges), the OVEC demand charges were added to the Preferred Portfolio costs to provide an “apples to apples” comparison with the OVEC 2030 Portfolio, which includes the total cost of the incremental supply resource that replaces I&M’s share of OVEC’s capacity.

The Company also conducted an analysis of its obligations associated with terminating the OVEC ICPA early based on forecasted information from OVEC. This analysis evaluated two early termination scenarios, 1) if only I&M terminated the ICPA early, and 2) if all sponsoring companies, including I&M, terminated the ICPA early (which in practicality means closure of the OVEC units). Under both scenarios, early termination costs included repayment of the remaining debt obligation and decommissioning costs. The scenario in which only I&M terminated the ICPA early also included I&M’s obligation through 2040 for ongoing demand-related costs. This assessment was based on the information available to I&M, and may not represent all costs I&M would incur in either scenario if the ICPA were terminated early. As stated previously though, the ICPA does not contain an early termination clause.

The results of the analysis estimated the net present value of I&M’s obligation under the first scenario to be approximately $102 million and under the second scenario to be approximately $28 million.

10 Short-Term Action Plan and Conclusion

The I&M IRP is regularly reviewed as new information becomes available. I&M intends to pursue the following activities for the IRP Short-Term Action Plan:

1. Continue the planning and regulatory actions necessary to implement additional cost-effective DSM programs in Indiana and Michigan consistent with this IRP that identified the potential for increased levels of cost-effective EE.
2. Obtain the capacity needed for the PJM Planning Year 2024/2025 deficit (currently estimated to be about 314 MW in this IRP).
3. Issue an All-Source RFP in the first quarter of 2022 to seek resources to satisfy the 2025 and 2026 needs (in-service by the end of 2024 and 2025), which the Preferred Portfolio identified as 800 MW of wind and 500 MW of solar.
4. Issue an All-Source RFP in 2023 or 2024 to satisfy identified needs, targeting 2027 and 2028 renewables, storage, and gas additions (in-service by the end of 2026 and 2027), totaling 800MW of solar, 60 MW of storage as a hybrid resource, and 1,000 MW of gas peaking.
5. Initiate efforts to evaluate Cook relicensing costs.
6. Adjust this action plan and future IRPs to reflect changing circumstances, as necessary.

Since the Company's last IRP, I&M accomplishments towards that Short-Term Action Plan included:

- The Company entered into a settlement agreement related to the Rockport Unit 2 bringing clarity to how Rockport Unit 2 will be used to serve customers after the lease ends.

- In this IRP, the Company included the introduction of additional battery storage technology as part of its Preferred Portfolio and is preparing an All-Source RFP in 2022 to solicit resource additions identified in 2025 and 2026.

- The Company completed a Market Potential Study in 2021 assessing the potential for DSM/EE over a twenty year forecast period and used these results in this IRP.

- As discussed in sections 6.2 and 6.3, the Company performed a Renewables RFP in November 2020 and an All-Source Informational RFP as part of this IRP to evaluate market prices for renewable resources.

- The Company continues to monitor PJM's Capacity Performance rule and has notified PJM of its intention to continue as Fixed Resource Requirement (FRR) Entity through the 2023/2024 PJM Planning Year ending May 31, 2024.

- Finally, while no federal regulatory requirements to reduce CO_2 emissions are in place, AEP has taken action to reduce and offset CO_2 emissions from its generating fleet. AEP expects CO_2 emissions from its operations to continue to decline due to the retirement of the Rockport Plant by 2029 and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities.

10.1 Conclusion:

This IRP incorporated an extensive and thorough process that engaged Stakeholders through five public Stakeholder meetings and tested several Scenarios and many different portfolios to arrive at a Preferred Portfolio. The Preferred Portfolio performs well across a range of metrics that were used in the Balanced Scorecard. The Preferred Portfolio is the best performing portfolio across multiple measures on the Balanced Scorecard and provides several additional benefits to I&M customers and Stakeholders, including the following:

Affordability and Rate Stability:

- The Preferred Portfolio is among the lowest reasonable cost portfolios measured on both a 20-year and 10-year cost to serve load metric. The only comparable portfolios are the Cook 2050+ life extension portfolios, which do not include consideration of the capital investments required to extend the life of those facilities (will be evaluated further in future IRPs).
- The Preferred Portfolio has one of the lowest absolute values for the 95th percentile value of NPV cost to serve load. All portfolios share a similar upside risk. This translates into having one of the lowest risk of increases in cost across the portfolios.
- Resource type additions in the Preferred Portfolio are similar through 2028 to the portfolios that modeled Cook license extensions (Cook 2050+), resulting in a “no regrets” position for the next several years.
- The Preferred Portfolio includes dispatchable resources that can enhance opportunities for wholesale sales without overexposure to market risks.
- The Preferred Portfolio takes advantage of existing tax incentives for new wind, solar and hybrid solar resources.
- The Preferred Portfolio requires the lowest capital requirements during the near-term planning period, which also lowers the risk associated with the availability of acquiring the necessary resources.

Market Risk

- The Preferred Portfolio mitigates overreliance on market purchases and sales for capacity and energy throughout the forecast horizon.
- The Preferred Portfolio requires short-term PJM capacity purchases for capacity in 2024 to replace Rockport Unit 2 capacity.
- Market purchases and sales of energy are reasonable and there is less reliance on the spot energy market, with the Preferred Portfolio averaging 7.2% for purchases and 19.8% for sales over the forecast horizon.
- The Preferred Portfolio results in small amounts of surplus capacity over the forecast period
- The Preferred Portfolio avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

Sustainability:

- The Preferred Portfolio leads to a lower carbon future, achieving 76% reduction by 2041, when including CO_2 emissions for short-term and spot market purchases, from 2005 levels that did not include CO_2 emissions assumptions from short-term and spot market purchases. Excluding short-term and spot market purchase emissions estimates, the Preferred Portfolio realizes CO_2 emissions reductions of 82% by 2041.
- The Preferred Portfolio includes a substantial amount of renewable resources as it continues to transform its fleet.
- The Preferred Portfolio maintains the optionality for the Cook License Extensions which maintains the opportunity to extend the operations of a significant emission-free resource.
- The Preferred Portfolio provides potential opportunities for natural gas conversion to hydrogen fuel later in the planning period.
- The Preferred Portfolio significantly reduces the reliance on coal fired generation by 2029.

Reliability and Resource Diversity:

- The Preferred Portfolio includes additions that when added to the Company's current resources, provides a more diversified portfolio of supply-side and demand-side resources that will allow the Company to optimize the use of each resource type to ensure the reliable supply of electricity while also maintaining PJM capacity requirements and supporting resource adequacy.
- The Combustion Turbine (CT) resources provide flexible, fast ramping capabilities and can help mitigate risks associated with intermittent renewable resource additions.
  The Preferred Portfolio manages the reliance on market purchases and sales for capacity and energy purposes. In addition, it avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

In conjunction with the Company's Short-Term Action Plan, the Preferred Portfolio offers I&M significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Portfolio.

Appendix Vol. 1 – Included in Hard Copy

Exhibit A	Load Forecast Table
Exhibit B	IRP Public Summary Document
Exhibit C	Case and Scenario Results
Exhibit D	New Generation Resources
Exhibit E	I&M Hourly Data
Exhibit G	Stakeholder Process Exhibits
Exhibit H	Cross Reference Table

Exhibit A Load Forecast Table

Exhibit A-1

Indiana Michigan Power Company
Annual Internal Energy Requirements and Growth Rates
2011-2041

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requiremen GWH	Total Internal Energy Requiremen % Grow
Actual												
2011	5,997	---	5,045	---	7,523	---	4,975	---	2,388	---	25,929	---
2012	5,771	-3.8	5,001	-0.9	7,556	0.4	5,112	2.8	2,290	-4.1	25,731	-0.8
2013	5,778	0.1	4,943	-1.2	7,522	-0.5	5,103	-0.2	2,374	3.6	25,719	0.0
2014	5,776	0.0	4,884	-1.2	7,640	1.6	5,103	0.0	2,339	-1.5	25,741	0.1
2015	5,483	-5.1	4,891	0.2	7,570	-0.9	5,033	-1.4	2,069	-11.5	25,047	-2.7
2016	5,578	1.7	4,979	1.8	7,780	2.8	5,121	1.8	1,949	-5.8	25,407	1.4
2017	5,311	-4.8	4,785	-3.9	7,781	0.0	5,032	-1.7	1,837	-5.8	24,745	-2.6
2018	5,731	7.9	4,852	1.4	7,836	0.7	4,678	-7.0	1,906	3.8	25,002	1.0
2019	5,409	-5.6	4,685	-3.4	7,589	-3.1	4,530	-3.2	1,855	-2.7	24,068	-3.7
2020	5,464	1.0	4,475	-4.5	7,225	-4.8	3,476	-23.3	1,645	-11.3	22,286	-7.4
Forecast												
2021*	5,399	-1.2	4,535	1.3	7,504	3.9	3,000	-13.7	1,800	9.4	22,237	-0.2
2022	5,420	0.4	4,496	-0.9	7,659	2.1	3,023	0.8	1,619	-10.1	22,217	-0.1
2023	5,441	0.4	4,532	0.8	7,647	-0.1	3,036	0.4	1,593	-1.6	22,250	0.2
2024	5,428	-0.3	4,551	0.4	7,603	-0.6	3,047	0.4	1,625	2.0	22,254	0.0
2025	5,440	0.2	4,557	0.1	7,624	0.3	3,013	-1.1	1,614	-0.6	22,248	0.0
2026	5,444	0.1	4,530	-0.6	7,648	0.3	2,993	-0.7	1,611	-0.2	22,226	-0.1
2027	5,444	0.0	4,504	-0.6	7,696	0.6	3,000	0.2	1,616	0.4	22,261	0.2
2028	5,453	0.2	4,489	-0.3	7,763	0.9	3,014	0.5	1,616	0.0	22,334	0.3
2029	5,463	0.2	4,482	-0.1	7,810	0.6	3,018	0.1	1,622	0.4	22,395	0.3
2030	5,467	0.1	4,492	0.2	7,853	0.6	3,027	0.3	1,627	0.3	22,466	0.3
2031	5,483	0.3	4,515	0.5	7,902	0.6	3,036	0.3	1,633	0.4	22,569	0.5
2032	5,502	0.3	4,530	0.3	7,950	0.6	3,049	0.4	1,640	0.4	22,670	0.4
2033	5,523	0.4	4,527	0.0	8,007	0.7	3,054	0.2	1,646	0.4	22,757	0.4
2034	5,543	0.4	4,530	0.1	8,064	0.7	1,188	-61.1	1,580	-4.0	20,905	-8.1
2035	5,566	0.4	4,541	0.2	8,110	0.6	514	-56.7	1,559	-1.3	20,289	-2.9
2036	5,589	0.4	4,556	0.3	8,149	0.5	514	0.1	1,566	0.4	20,374	0.4
2037	5,615	0.5	4,564	0.2	8,188	0.5	515	0.1	1,572	0.4	20,453	0.4
2038	5,639	0.4	4,563	0.0	8,232	0.5	251	-51.3	1,564	-0.5	20,248	-1.0
2039	5,664	0.4	4,510	-1.2	8,280	0.6	65	-74.0	1,560	-0.2	20,079	-0.8
2040	5,688	0.4	4,472	-0.8	8,324	0.5	65	-0.1	1,561	0.1	20,111	0.2
2041	5,711	0.4	4,504	0.7	8,360	0.4	65	-0.1	1,569	0.5	20,210	0.5

*Includes 6 months actual and 6 months forecast data.

Average Annual Growth Rates	Residential % Growth	Commercial % Growth	Industrial % Growth	Other Internal % Growth	Losses % Growth	Total % Grow
2011-2020	-1.0	-1.3	-0.4	-3.9	-4.1	-1.7
2022-2041	0.3	0.0	0.5	-18.3	-0.2	-0.5

Exhibit A-2a

Indiana Michigan Power Company-Indiana
Annual Internal Energy Requirements and Growth Rates
2011-2041

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requiremen GWH	Total Internal Energy Requiremen % Grow
Actual												
2011	4,750	---	4,240	---	6,727	---	4,352	---	1,744	---	21,814	---
2012	4,553	-4.1	4,183	-1.3	6,755	0.4	4,477	2.9	1,713	-1.8	21,681	-0.6
2013	4,564	0.2	4,134	-1.2	6,709	-0.7	4,483	0.1	1,713	0.0	21,603	-0.4
2014	4,556	-0.2	4,090	-1.1	6,809	1.5	4,479	-0.1	1,660	-3.1	21,594	0.0
2015	4,314	-5.3	4,086	-0.1	6,729	-1.2	4,412	-1.5	1,365	-17.7	20,906	-3.2
2016	4,392	1.8	4,151	1.6	6,948	3.3	4,487	1.7	1,148	-16.0	21,127	1.1
2017	4,165	-5.2	3,977	-4.2	6,965	0.2	4,422	-1.4	1,038	-9.5	20,568	-2.6
2018	4,510	8.3	4,042	1.6	7,018	0.8	4,055	-8.3	1,580	52.1	21,204	3.1
2019	4,246	-5.8	3,910	-3.3	6,794	-3.2	3,925	-3.2	1,505	-4.7	20,380	-3.9
2020	4,268	0.5	3,736	-4.5	6,461	-4.9	3,210	-18.2	1,331	-11.5	19,005	-6.7
Forecast												
2021*	4,216	-1.2	3,776	1.1	6,731	4.2	2,932	-8.7	1,510	13.4	19,165	0.8
2022	4,240	0.6	3,740	-1.0	6,897	2.5	2,953	0.7	1,369	-9.3	19,198	0.2
2023	4,259	0.4	3,766	0.7	6,874	-0.3	2,965	0.4	1,346	-1.6	19,210	0.1
2024	4,246	-0.3	3,782	0.4	6,828	-0.7	2,976	0.4	1,372	1.9	19,205	0.0
2025	4,254	0.2	3,790	0.2	6,846	0.3	2,978	0.0	1,365	-0.6	19,231	0.1
2026	4,257	0.1	3,770	-0.5	6,866	0.3	2,983	0.2	1,362	-0.2	19,239	0.0
2027	4,259	0.0	3,750	-0.5	6,909	0.6	2,990	0.2	1,368	0.4	19,276	0.2
2028	4,267	0.2	3,739	-0.3	6,972	0.9	3,004	0.5	1,368	0.0	19,350	0.4
2029	4,276	0.2	3,733	-0.1	7,016	0.6	3,008	0.1	1,373	0.4	19,407	0.3
2030	4,281	0.1	3,736	0.1	7,056	0.6	3,017	0.3	1,377	0.3	19,468	0.3
2031	4,295	0.3	3,753	0.4	7,102	0.6	3,026	0.3	1,383	0.4	19,558	0.5
2032	4,311	0.4	3,768	0.4	7,147	0.6	3,039	0.4	1,389	0.4	19,654	0.5
2033	4,330	0.4	3,767	0.0	7,201	0.8	3,044	0.2	1,395	0.4	19,736	0.4
2034	4,348	0.4	3,769	0.1	7,254	0.7	1,179	-61.3	1,328	-4.8	17,879	-9.4
2035	4,369	0.5	3,780	0.3	7,297	0.6	504	-57.2	1,307	-1.6	17,257	-3.5
2036	4,390	0.5	3,794	0.4	7,332	0.5	505	0.1	1,313	0.5	17,335	0.5
2037	4,413	0.5	3,802	0.2	7,368	0.5	505	0.1	1,319	0.4	17,407	0.4
2038	4,435	0.5	3,800	-0.1	7,408	0.6	242	-52.2	1,311	-0.6	17,195	-1.2
2039	4,458	0.5	3,748	-1.4	7,453	0.6	56	-76.7	1,307	-0.3	17,022	-1.0
2040	4,480	0.5	3,712	-1.0	7,494	0.5	56	0.1	1,308	0.1	17,049	0.2
2041	4,501	0.5	3,743	0.8	7,527	0.4	56	0.1	1,315	0.6	17,143	0.5

*Includes 6 months actual and 6 months forecast data.

Average Annual Growth Rates	Residential % Growth	Commercial % Growth	Industrial % Growth	Other Internal % Growth	Losses % Growth	Total % Growth
2011-2020	-1.2	-1.4	-0.4	-3.3	-3.0	-1.5
2022-2041	0.3	0.0	0.5	-18.8	-0.2	-0.6

Exhibit A-2b

Indiana Michigan Power Company-Michigan
Annual Internal Energy Requirements and Growth Rates
2011-2041

Year	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requiremen GWH	Total Internal Energy Requiremen % Grow
Actual												
2011	1,248	---	805	---	796	---	623	---	644	---	4,114	---
2012	1,217	-2.4	818	1.7	802	0.8	635	1.9	577	-10.3	4,050	-1.6
2013	1,215	-0.2	809	-1.1	813	1.4	619	-2.5	660	14.3	4,116	1.6
2014	1,219	0.4	794	-1.9	831	2.2	624	0.8	679	2.8	4,147	0.8
2015	1,169	-4.2	806	1.5	841	1.2	621	-0.5	704	3.7	4,140	-0.2
2016	1,186	1.4	828	2.8	831	-1.1	634	2.0	802	13.9	4,280	3.4
2017	1,145	-3.4	808	-2.4	816	-1.8	609	-3.8	798	-0.5	4,177	-2.4
2018	1,221	6.6	810	0.2	818	0.3	623	2.3	326	-59.2	3,798	-9.1
2019	1,162	-4.8	775	-4.3	795	-2.9	605	-2.9	350	7.4	3,688	-2.9
2020	1,197	3.0	740	-4.6	764	-3.9	266	-56.0	314	-10.3	3,280	-11.0
Forecast												
2019*	1,182	-1.2	760	2.7	772	1.1	68	-74.4	290	-7.6	3,073	-6.3
2022	1,180	-0.2	757	-0.4	762	-1.3	70	2.5	250	-13.8	3,018	-1.8
2023	1,183	0.2	766	1.3	774	1.5	71	1.3	247	-1.2	3,041	0.7
2024	1,181	-0.1	768	0.2	776	0.3	71	0.5	253	2.3	3,049	0.3
2025	1,187	0.5	767	-0.2	778	0.3	35	-50.4	250	-1.1	3,017	-1.1
2026	1,186	0.0	760	-0.9	782	0.4	10	-71.1	248	-0.6	2,987	-1.0
2027	1,185	-0.1	754	-0.8	786	0.6	10	-0.6	249	0.2	2,985	-0.1
2028	1,186	0.0	750	-0.5	791	0.6	10	-0.7	248	-0.3	2,985	0.0
2029	1,186	0.1	749	-0.2	794	0.4	10	-0.8	249	0.2	2,988	0.1
2030	1,186	0.0	756	1.0	797	0.4	10	-0.8	249	0.3	2,999	0.4
2031	1,188	0.2	763	0.8	800	0.4	10	-0.8	250	0.4	3,011	0.4
2032	1,191	0.2	762	-0.1	803	0.3	10	-0.9	251	0.2	3,015	0.1
2033	1,193	0.2	761	-0.1	806	0.4	10	-0.9	251	0.2	3,021	0.2
2034	1,195	0.2	761	0.0	810	0.4	10	-1.0	251	0.1	3,026	0.2
2035	1,197	0.2	761	0.1	813	0.4	9	-1.0	252	0.1	3,032	0.2
2036	1,199	0.2	762	0.1	817	0.4	9	-1.0	252	0.2	3,039	0.2
2037	1,202	0.2	762	0.1	820	0.4	9	-1.0	253	0.2	3,046	0.2
2038	1,204	0.2	763	0.1	823	0.4	9	-1.1	253	0.2	3,053	0.2
2039	1,206	0.2	762	-0.1	827	0.4	9	-1.1	254	0.1	3,057	0.2
2040	1,208	0.1	761	-0.2	830	0.4	9	-1.2	254	0.1	3,061	0.1
2041	1,209	0.1	761	0.1	834	0.4	9	-1.2	255	0.3	3,067	0.2

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates

	Residential % Growth	Commercial % Growth	Industrial % Growth	Other Internal % Growth	Losses % Growth	Total Internal % Grow
2011-2020	-0.5	-0.9	-0.5	-9.0	-7.7	-2.5
2022-2041	0.1	0.0	0.5	-10.3	0.1	0.1

Exhibit A-3

Indiana Michigan Power Company
Composition of Forecast of Other Internal Sales (GWh)
2019-2038

	Indiana			Michigan			Total Company		
Year	Street Lighting	Wholesale	Total	Street Lighting	Wholesale	Total	Street Lighting	Wholesale	Total
2022	56	2,897	2,953	10	60	70	67	2,957	3,023
2023	56	2,909	2,965	10	61	71	66	2,970	3,036
2024	56	2,920	2,976	10	61	71	66	2,981	3,047
2025	56	2,922	2,978	10	25	35	66	2,947	3,013
2026	56	2,927	2,983	10	0	10	66	2,927	2,993
2027	56	2,934	2,990	10	0	10	66	2,934	3,000
2028	56	2,948	3,004	10	0	10	66	2,948	3,014
2029	56	2,952	3,008	10	0	10	66	2,952	3,018
2030	56	2,961	3,017	10	0	10	66	2,961	3,027
2031	56	2,970	3,026	10	0	10	66	2,970	3,036
2032	56	2,983	3,039	10	0	10	66	2,983	3,049
2033	56	2,988	3,044	10	0	10	66	2,988	3,054
2034	56	1,123	1,179	10	0	10	66	1,123	1,188
2035	56	448	504	9	0	9	65	448	514
2036	56	449	505	9	0	9	65	449	514
2037	56	449	505	9	0	9	65	449	515
2038	56	185	242	9	0	9	65	185	251
2039	56	0	56	9	0	9	65	0	65
2040	56	0	56	9	0	9	65	0	65
2041	56	0	56	9	0	9	65	0	65

Exhibit A-4

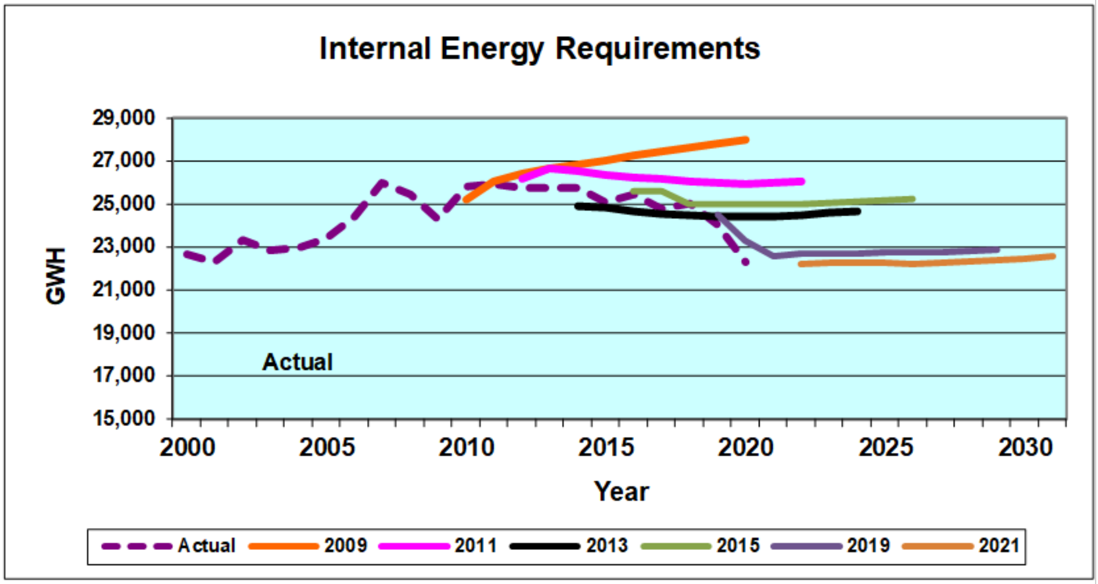
Indiana Michigan Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2011-2041

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2011	07/21/11	4,837	---	12/13/10	3,785	---	4,837	---	25,929	---	61.2
2012	07/06/12	4,726	-2.3	01/20/12	3,686	-2.6	4,726	-2.3	25,731	-0.8	62.2
2013	09/10/13	4,540	-3.9	01/22/13	3,782	2.6	4,540	-3.9	25,719	0.0	64.7
2014	09/05/14	4,388	-3.4	01/22/14	3,938	4.1	4,388	-3.4	25,741	0.1	66.8
2015	07/28/15	4,398	0.2	01/14/15	3,952	0.4	4,398	0.2	25,047	-2.7	65.0
2016	08/11/16	4,547	3.4	01/13/16	3,702	-6.3	4,547	3.4	25,407	1.4	63.8
2017	07/19/17	4,230	-7.0	12/15/16	3,795	2.5	4,230	-7.0	24,745	-2.6	66.8
2018	06/18/18	4,369	3.3	01/16/18	3,723	-1.9	4,369	3.3	25,002	1.0	65.1
2019	07/15/19	4,191	-4.1	01/30/19	3,766	1.2	4,191	-4.1	24,068	-3.7	65.5
2020	07/09/20	3,970	-5.3	12/19/19	3,445	-8.5	3,970	-5.3	22,286	-7.4	64.1
Forecast											
2021*		4,398	10.8		3,365	-2.3	3,930	-1.0	22,237	-0.2	64.6
2022		3,932	-10.6		3,380	0.4	3,932	0.0	22,217	-0.1	64.3
2023		3,942	0.2		3,378	-0.1	3,942	0.2	22,250	0.2	64.4
2024		3,936	-0.1		3,368	-0.3	3,936	-0.1	22,254	0.0	64.5
2025		3,943	0.2		3,382	0.4	3,943	0.2	22,248	0.0	64.4
2026		3,944	0.0		3,372	-0.3	3,944	0.0	22,226	-0.1	64.2
2027		3,949	0.1		3,374	0.1	3,949	0.1	22,261	0.2	64.4
2028		3,952	0.1		3,375	0.0	3,952	0.1	22,334	0.3	64.5
2029		3,972	0.5		3,391	0.5	3,972	0.5	22,395	0.3	64.4
2030		3,985	0.3		3,400	0.3	3,985	0.3	22,466	0.3	64.2
2031		4,004	0.5		3,414	0.4	4,004	0.5	22,569	0.5	64.3
2032		4,012	0.2		3,417	0.1	4,012	0.2	22,670	0.4	64.5
2033		4,038	0.6		3,439	0.7	4,038	0.6	22,757	0.4	64.3
2034		3,670	-9.1		3,298	-4.1	3,670	-9.1	20,905	-8.1	64.8
2035		3,685	0.4		3,108	-5.7	3,685	0.4	20,289	-2.9	62.8
2036		3,691	0.2		3,115	0.2	3,691	0.2	20,374	0.4	63.0
2037		3,717	0.7		3,138	0.7	3,717	0.7	20,453	0.4	62.8
2038		3,659	-1.6		3,143	0.1	3,659	-1.6	20,248	-1.0	63.0
2039		3,661	0.1		3,065	-2.5	3,661	0.1	20,079	-0.8	62.6
2040		3,657	-0.1		3,059	-0.2	3,657	-0.1	20,111	0.2	62.8
2041		3,690	0.9		3,081	0.7	3,690	0.9	20,210	0.5	62.5

*Total energy requirements reflect 3 months actual and 9 months forecast data.

Exhibit A-5

INDIANA MICHIGAN POWER COMPANY
COMPARISON OF FORECASTS



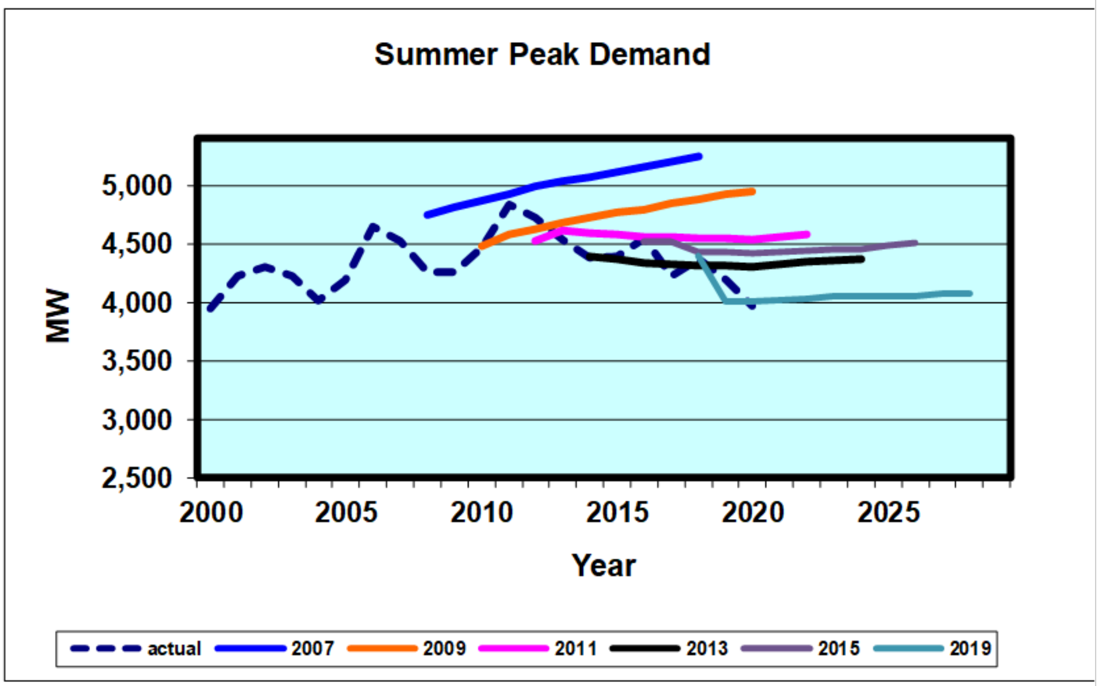


Exhibit A-6

Indiana Michigan Power Company
Profiles of Monthly Peak Internal Demands
2008, 2013, 2018 (Actual)
2028 and 2038

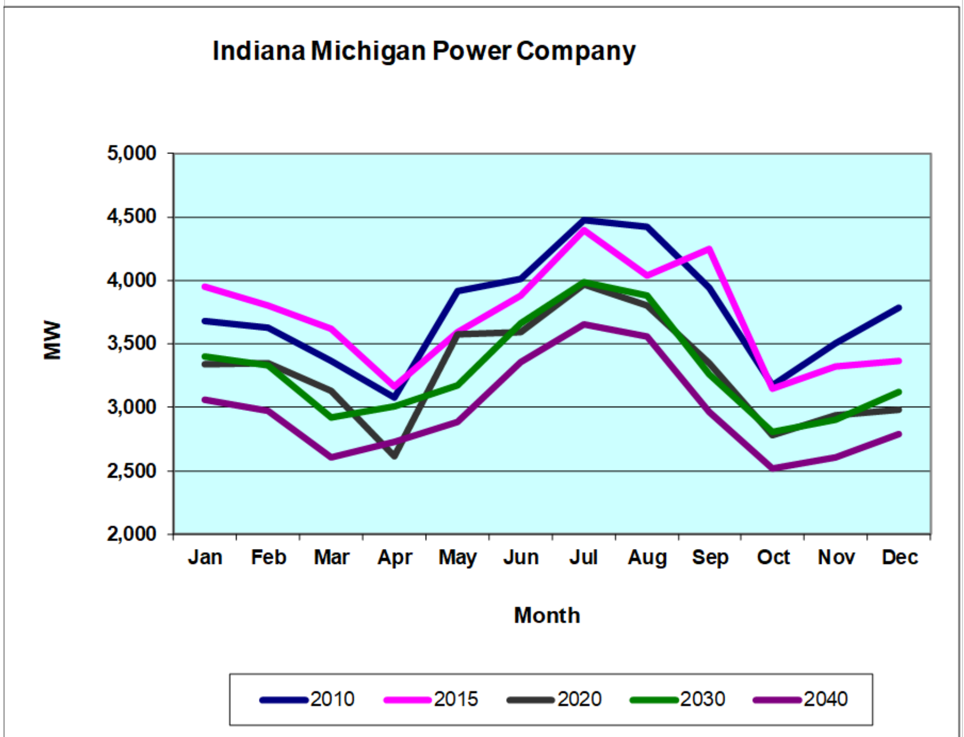
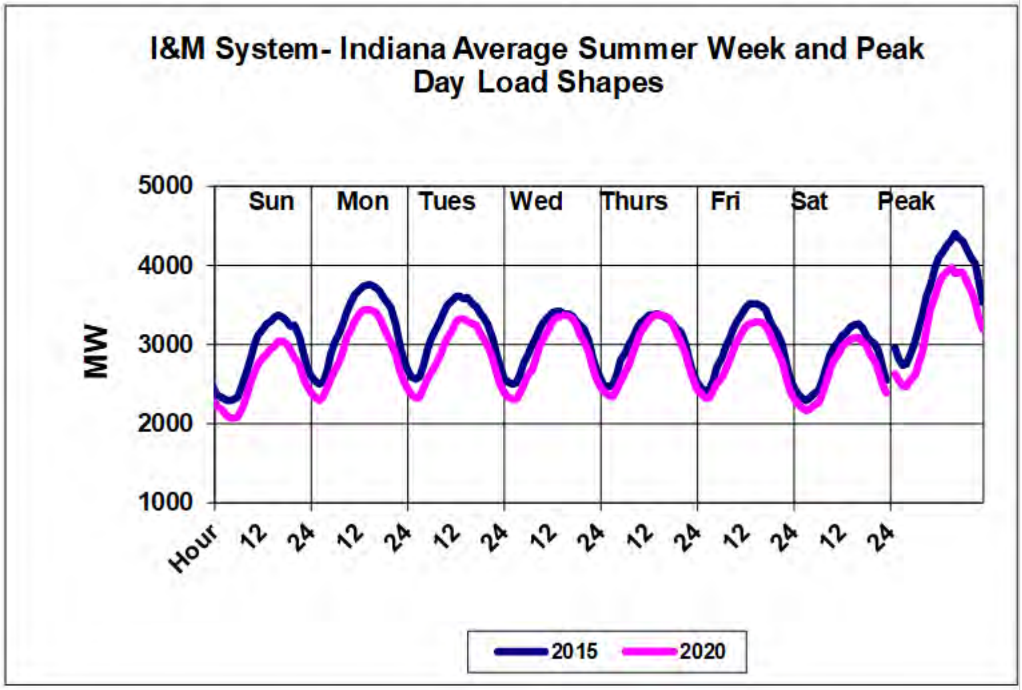


Exhibit A-7


I&M System- Indiana Average Summer Week and Peak Day Load Shapes
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3000
2000
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Hour
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2015
2020

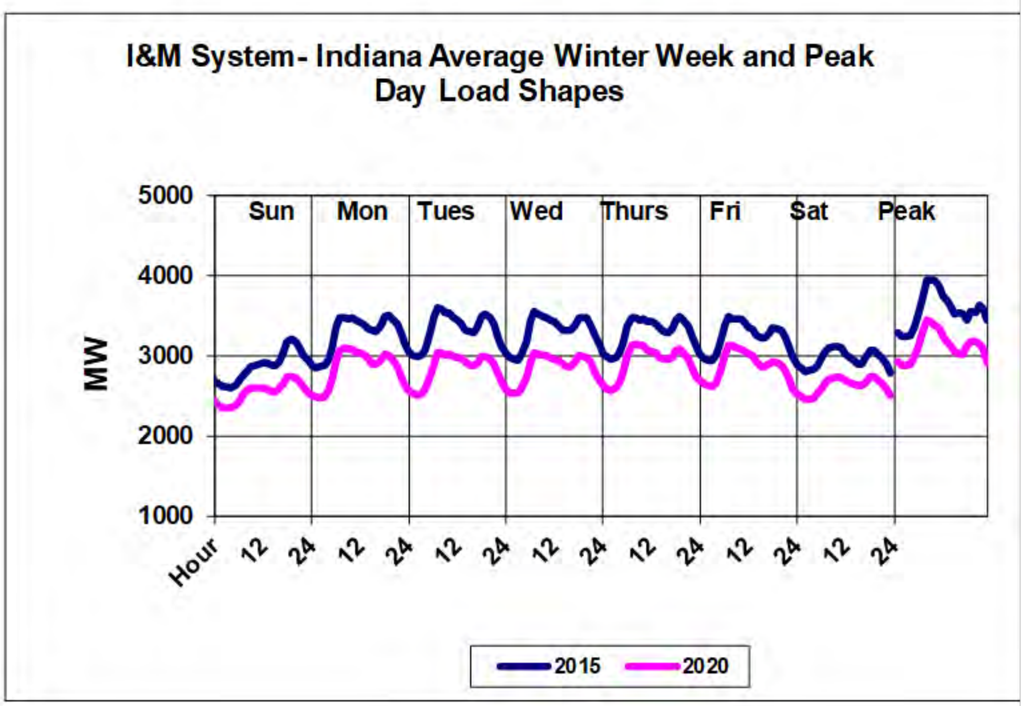
I&M System- Indiana Average Winter Week and Peak Day Load Shapes
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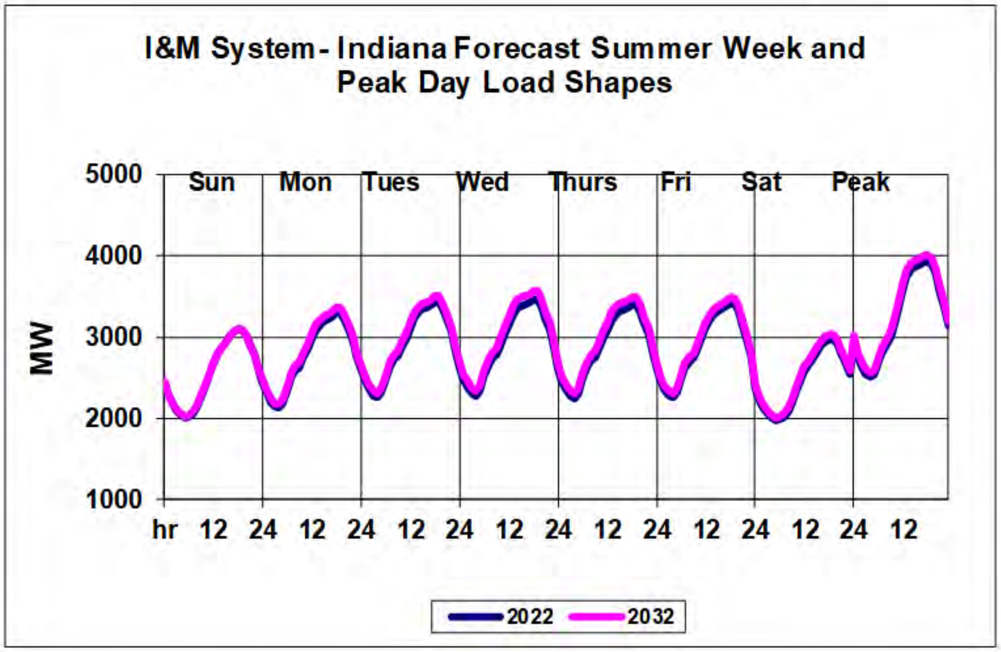
Exhibit A-8


I&M System- Indiana Forecast Summer Week and Peak Day Load Shapes
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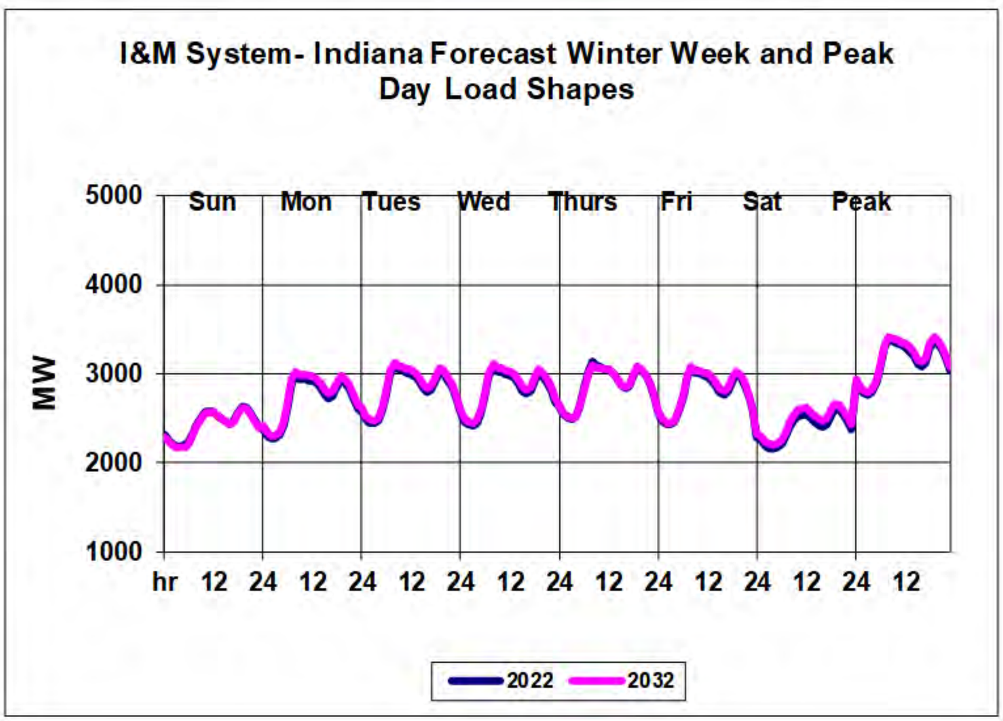
I&M System- Indiana Forecast Winter Week and Peak Day Load Shapes
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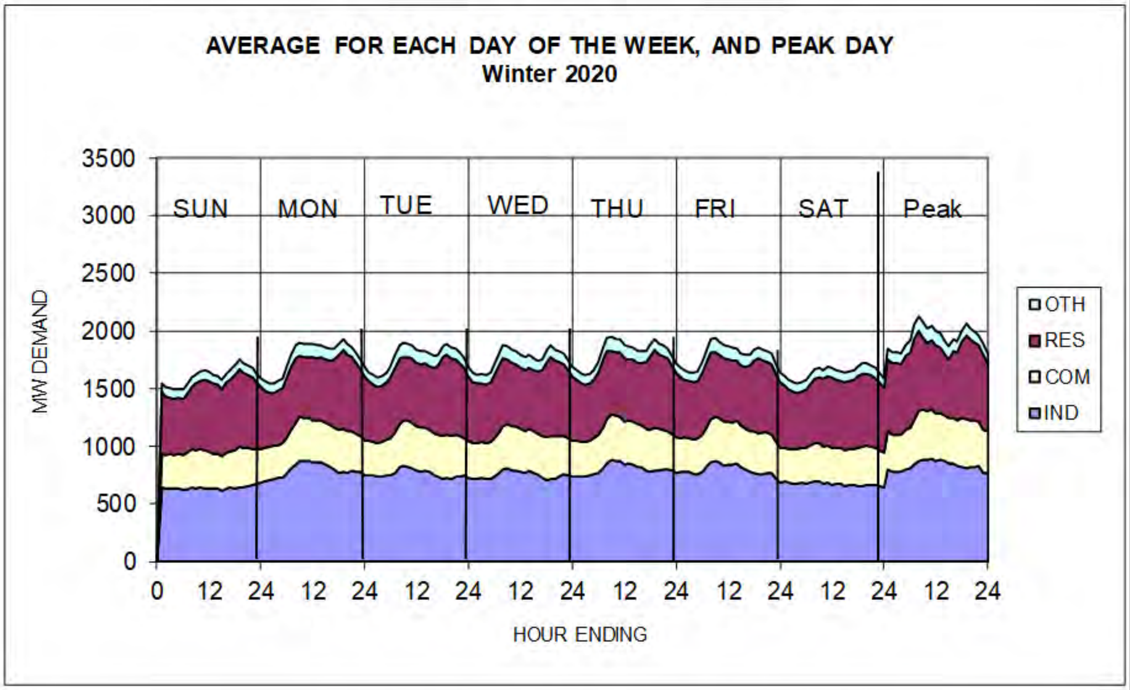
Exhibit A-9

I&M - INDIANA JURISDICTION
HOURLY DEMAND BY CLASS



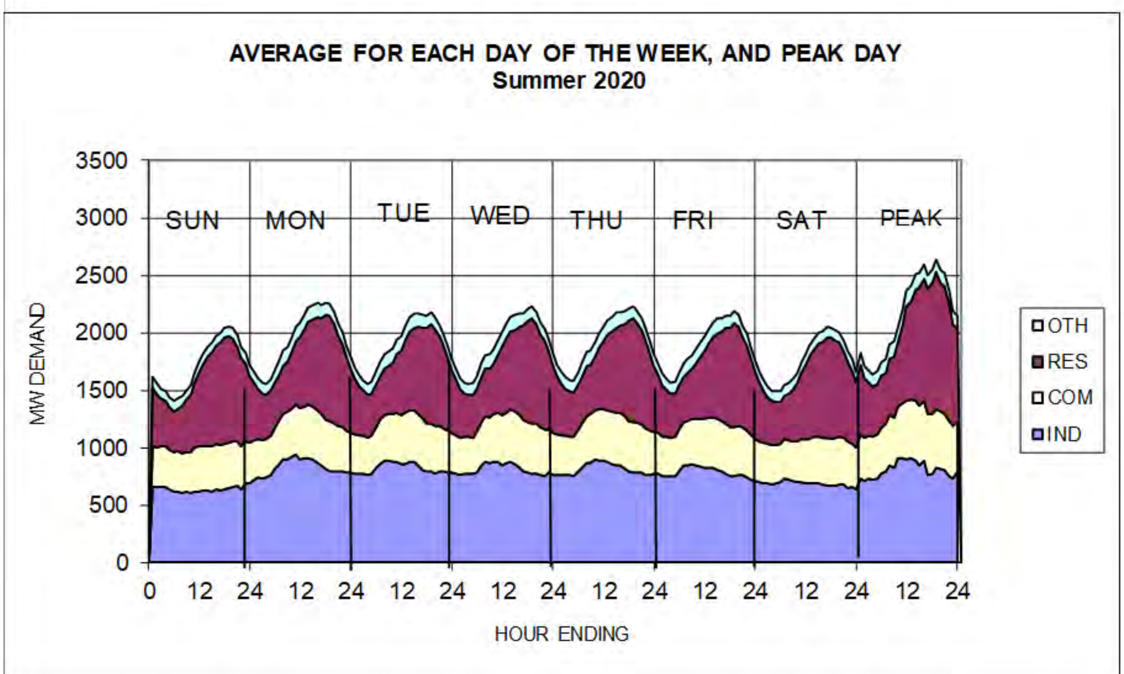


Exhibit A-10

Indiana Michigan Power Company
Recorded and Weather Normalized Peak Load (MW) and Energy (GWh)
2011-2020

Indiana Michigan Power Company	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
A. Peak Load - Summer										
1. Recorded	4,837	4,726	4,540	4,388	4,398	4,547	4,230	4,369	4,191	3,970
2. Weather - Normalized	4,479	4,584	4,577	4,519	4,532	4,580	4,512	4,407	4,244	3,955
B. Peak Load - Preceding Winter										
1. Recorded	3,785	3,686	3,782	3,938	3,952	3,702	3,795	3,723	3,766	3,445
2. Weather - Normalized	3,808	3,813	3,804	3,825	3,811	3,744	3,704	3,728	3,654	3,555
C. Energy										
1. Recorded	25,929	25,731	25,719	25,741	25,047	25,407	24,745	25,002	24,068	22,286
2. Weather - Normalized	25,646	25,651	25,660	25,654	25,100	25,285	25,029	24,576	23,933	22,354

Exhibit A-11

INDIANA MICHIGAN POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1984-2020	NOAA (1) Weather Bank	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/84-1/21	NOAA (1) Weather Bank	
Gross Regional Product, Manufacturing	Monthy	U. S.	1984-2057	Moody's Analytics (2)	Extrapolated Forecast
Implicit Deflator-Gross Domestic Product	Monthly	U. S.	1980-2057	Moody's Analytics (2)	Extrapolated Forecast
U.S. Gas Prices, U.S. Gas Consumption	Monthly	U.S.	1980-2057	DOE/EIA (6)	Growth rates used for forecast with historical data, extrapolated forecast
Federal Reserve Board Industrial Production Indexes - Selected Industries	Monthly	U. S.	1975-2057	Moody's Analytics (2) FRB (3)	None
Residential Appliance Efficiencies, Saturation Trends, Housing Size	Annual, Monthly	East North Central Census Region	1995-2057	DOE via Itron(7) Itron	Extrapolated projections, applied trends to Company Saturations
Commericial Equipment Efficiencies, Saturations Square-Footage	Annual, Monthly	East North Central Census Region	1995-2057	DOE via Itron(8) Itron	Extrapolated projections
U. S., Indiana and Michigan Natural Gas Prices by Sector	Monthly	U. S.	1980-2020	DOE/EIA (4)	None
Gross Regional Product	Monthly	Selected Indiana and Michigan Counties	1980-2057	Moody's Analytics (5)	Extrapolated Forecast
Employment (Total and Selected Sectors), Personal Income and Population	Monthly	Selected Indiana and Michigan Counties	1980-2057	Moody's Analytics (5)	Extrapolated Forecast

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) January 2021 Forecast, Moody's Analytics
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2020
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly," Selected Issues.
(5) January 2021 Regional Forecast, Moody's Analytics
(6) U.S. Department of Energy/Energy Information Administration "Annual Energy Outlook 2021 with Projections to 2050" .
(8) Itron Summer 2020, DOE "Annual Energy Outlook 2020"
(7) Itron Summer 2020 DOE "Annual Energy Outlook 2020"

Exhibit A-12

Indiana Michigan and Indiana and Michigan Jurisdictions
DSM/Energy Efficiency Included in Load Forecast
Energy (GWh) and Coincident Peak Demand (MW)

	I&M DSM/EE			I&M - Indiana DSM/EE			I&M - Michigan DSM/EE		
Year	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand	Energy	Summer* Demand	Winter* Demand
2022	27.0	6.0	8.7	20.3	5.6	7.9	6.7	0.4	0.8
2023	37.6	8.1	8.3	29.1	7.6	5.8	8.4	0.5	2.5
2024	33.0	5.7	8.3	27.3	5.4	6.6	5.7	0.3	1.7
2025	31.5	1.9	8.8	28.6	1.5	8.4	2.9	0.5	0.4
2026	53.3	5.0	12.2	44.6	3.5	11.0	8.7	1.5	1.2
2027	72.9	7.7	15.2	59.1	5.4	13.4	13.9	2.3	1.9
2028	89.2	10.0	17.6	71.2	7.0	15.2	18.1	3.0	2.5
2029	93.8	11.0	17.9	75.1	7.8	15.3	18.8	3.2	2.6
2030	70.3	7.6	14.2	61.9	6.2	13.0	8.4	1.4	1.1
2031	38.8	2.9	9.8	38.8	2.9	9.8	0.0	0.0	0.0
2032	19.1	0.0	7.2	19.1	0.0	7.2	0.0	0.0	0.0
2033	19.1	0.0	7.2	19.1	0.0	7.2	0.1	0.0	0.0
2034	17.4	0.0	6.6	17.4	0.0	6.6	0.0	0.0	0.0
2035	10.9	0.0	8.4	10.9	0.0	8.4	0.0	0.0	0.0
2036	1.3	0.0	1.0	1.3	0.0	1.0	0.0	0.0	0.0
2037	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2038	10.4	2.2	5.0	10.1	2.1	4.9	0.3	0.1	0.1
2039	77.9	16.5	18.2	75.7	16.0	17.7	2.2	0.5	0.5
2040	121.8	25.8	28.3	118.4	25.1	27.5	3.4	0.7	0.8
2041	92.1	19.4	21.4	89.5	18.9	20.8	2.5	0.6	0.6

***Demand coincident with Company's seasonal peak demand.**

Exhibit A-13

Indiana Michigan Power Company
Short-Term Load Forecast
Blended Forecast vs. Long-Term Model Results

Class	Indiana	Michigan
Residential	Long-Term	Long-Term
Commercial	Long-Term	Long-Term
Industrial	Long-Term	Long-Term
Other Retail	Long-Term	Long-Term

Exhibit A-14

Blending Illustration

Month	Short-term Forecast	Weight	Long-term Forecast	Weight	Blended Forecast
1	1,000	100%	1,150	0%	1,000
2	1,010	100%	1,160	0%	1,010
3	1,020	100%	1,170	0%	1,020
4	1,030	100%	1,180	0%	1,030
5	1,040	83%	1,190	17%	1,065
6	1,050	67%	1,200	33%	1,100
7	1,060	50%	1,210	50%	1,135
8	1,070	33%	1,220	67%	1,170
9	1,080	17%	1,230	83%	1,205
10	1,090	0%	1,240	100%	1,240
11	1,100	0%	1,250	100%	1,250
12	1,110	0%	1,260	100%	1,260

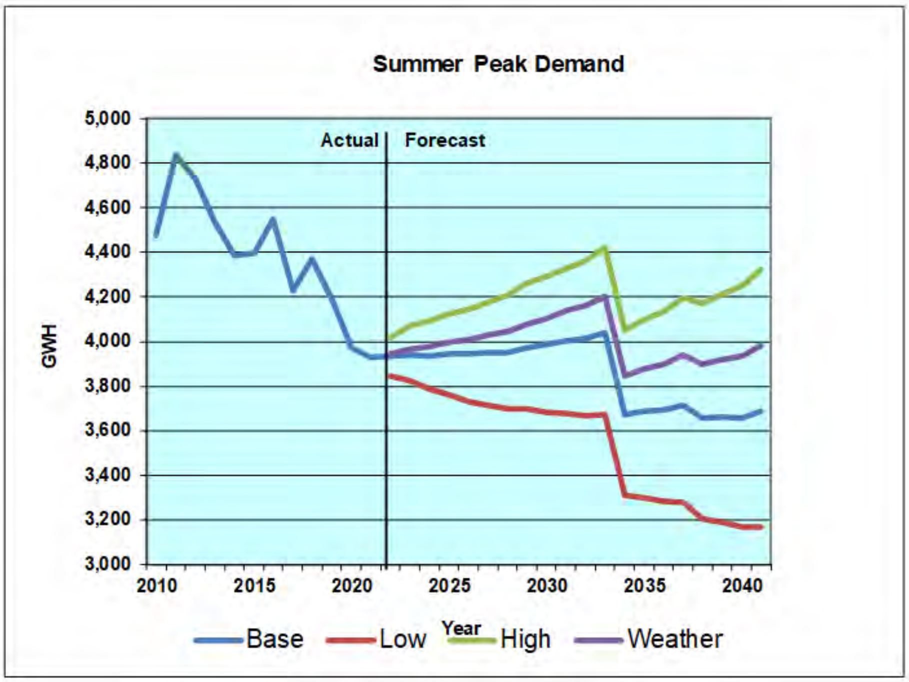
Exhibit A-15

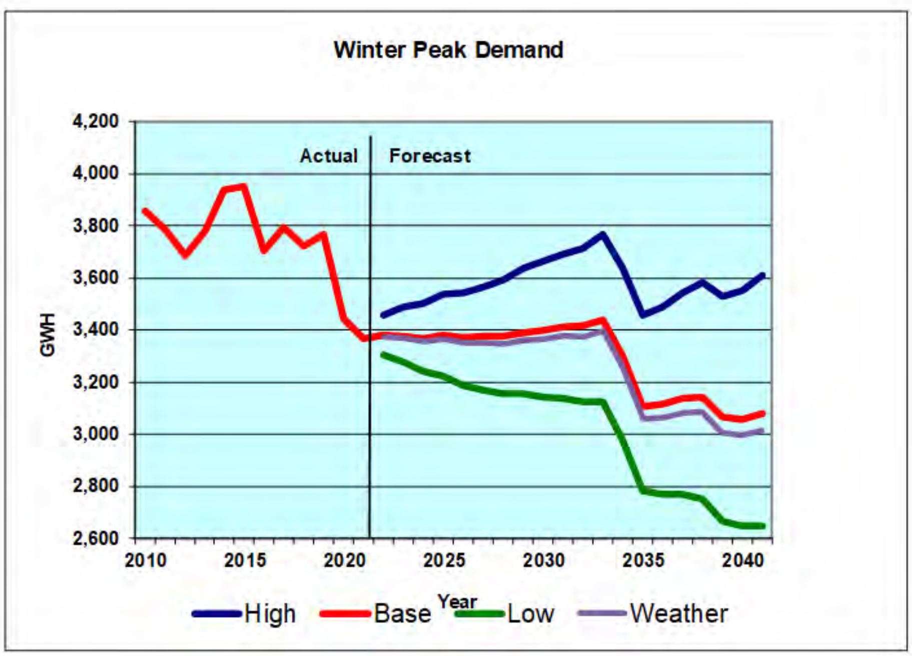
Indiana Michigan Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2022	3,303	3,380	3,456	3,843	3,932	4,020	21,713	22,217	22,713
2023	3,277	3,378	3,487	3,824	3,942	4,069	21,584	22,250	22,970
2024	3,240	3,368	3,503	3,786	3,936	4,093	21,406	22,254	23,144
2025	3,224	3,382	3,536	3,759	3,943	4,123	21,211	22,248	23,263
2026	3,189	3,372	3,543	3,731	3,944	4,145	21,023	22,226	23,358
2027	3,172	3,374	3,567	3,712	3,949	4,174	20,924	22,261	23,530
2028	3,158	3,375	3,594	3,698	3,952	4,208	20,899	22,334	23,783
2029	3,156	3,391	3,635	3,696	3,972	4,258	20,841	22,395	24,006
2030	3,144	3,400	3,663	3,685	3,985	4,293	20,775	22,466	24,204
2031	3,136	3,414	3,692	3,678	4,004	4,330	20,734	22,569	24,405
2032	3,123	3,417	3,711	3,668	4,012	4,359	20,725	22,670	24,626
2033	3,126	3,439	3,767	3,670	4,038	4,423	20,686	22,757	24,926
2034	2,974	3,298	3,638	3,310	3,670	4,048	18,855	20,905	23,059
2035	2,783	3,108	3,455	3,300	3,685	4,097	18,168	20,289	22,553
2036	2,769	3,115	3,490	3,282	3,691	4,136	18,114	20,374	22,827
2037	2,770	3,138	3,545	3,281	3,717	4,198	18,054	20,453	23,105
2038	2,753	3,143	3,582	3,206	3,659	4,171	17,741	20,248	23,081
2039	2,668	3,065	3,528	3,187	3,661	4,214	17,480	20,079	23,113
2040	2,648	3,059	3,554	3,166	3,657	4,249	17,410	20,111	23,361
2041	2,646	3,081	3,608	3,169	3,690	4,322	17,359	20,210	23,670
Average Annual Growth Rate % - 2022-2041									
	-1.2	-0.5	0.2	-1.0	-0.3	0.4	-1.2	-0.5	0.2

Exhibit A-16

Indiana Michigan Power Company
Range of Forecasts and Weather Scenario





Indiana Michigan Power Company

Forecasted DSM, Adjusted for IRP Modeling

Exhibit A-17

	Indiana Michigan		
Year	Energy (MWh)	Summer Peak (MW)	Winter Peak (MW)
2021	13,351	2.5	3.5
2022	27,041	6.0	8.7
2023	14,856	1.8	0.3
2024	-	-	-
2025	-	-	-
2026	-	-	-
2027	-	-	-
2028	-	-	-
2029	-	-	-
2030	-	-	-
2031	-	-	-
2032	-	-	-
2033	-	-	-
2034	-	-	-
2035	-	-	-
2036	-	-	-
2037	-	-	-
2038	-	-	-
2039	-	-	-
2040	-	-	-
2041	-	-	-

Exhibit B IRP Public Summary Document

2021 INTEGRATED RESOURCE PLANNING

PUBLIC SUMMARY

January 31, 2021




INDIANA
MICHIGAN
POWER

An AEP Company

BOUNDLESS ENERGY

I&M 2021 IRP Public Summary

This 2021 Integrated Resource Plan (IRP, Plan, or Report) is submitted by Indiana Michigan Power Company (I&M or Company) based upon the best information available at the time of preparation. The purpose of the IRP is to develop a set of supply- and demand-side resources that guides how I&M generates and supplies electricity in a way that balances affordability, sustainability, and reliability.

This Plan is not a firm commitment to specific resource additions or other courses of action over the period of the plan, as the future is uncertain. The Plan provides the basis for a short-term course of action and strives to maintain optionality in meeting I&M's resource obligations in order for the Company to take advantage of market opportunities and technological advancements. Accordingly, this IRP includes a near-term plan, 2022 – 2028, and a long-term-indicative plan, 2029 – 2041, based on a number of assumptions that are subject to change as new information becomes available or as circumstances warrant.

I&M is on the brink of a major generation transformation as Rockport Unit 1 and Unit 2 will retire by the end of 2028. These coal-fired resources represent nearly one-half of the Company's generation fleet and the retirement of these units provides a significant opportunity for I&M to transition to more renewable resources, further diversify I&M's generation portfolio, and reduce its carbon emissions[1]. At the core of this transformation must be reliability, resiliency and affordability. To assess this, during the IRP development I&M established a Balanced Scorecard that evaluated a wide range of potential portfolios against metrics that included: affordability, rate stability, sustainability impact, market risk minimization, reliability, and resource diversity. Additionally, I&M's Preferred Portfolio was developed with the understanding that significant resource decisions will need to be made in the future regarding the possibility to extend the operating life of the Cook Nuclear Plant.

[1] I&M is part of American Electric Power (AEP), and AEP has set carbon emission reduction goals to achieve 80% reduction by 2030 from a 2000 baseline and net zero emissions by 2050. See AEPs-Climate-Impact-Analysis-2021.pdf (aepsustainability.com).

Indiana Michigan Power Company (I&M or Company) customers consist of both retail and sales-for-resale (wholesale) customers located in the states of Indiana and Michigan (Figure 1). Currently, I&M serves approximately 471,000 and 130,000 retail customers in the states of Indiana and Michigan, respectively. The peak load requirement of I&M's total retail and wholesale customers is seasonal in nature, with distinctive peaks occurring in the summer and winter seasons. I&M's all-time highest recorded peak demand was 4,837MW, which occurred in July 2011; and the highest recorded winter peak was 3,952MW, which occurred in January 2015. The most recent (summer 2020 and winter 2020/21) actual I&M summer and winter peak demands at the time this process began were 3,970MW and 3,365MW, occurring on July 19, 2020 and February 17, 2021, respectively.

Figure 1: I&M Service Territory and Generating Locations

Over the next 20-year period (2022-2041), I&M's service territory is expected to see population and non-farm employment growth of 0.0% and 0.4% per year, respectively. Not surprisingly, I&M is projected to see customer count growth at a similar rate of 0.1% per year. Over the same forecast period, I&M's retail sales are projected to grow at 0.3% per year with stronger growth expected from the industrial class (+0.46% per year) while the residential class experiences 0.3% CAGR and the commercial class remains relatively flat over the forecast horizon. Finally, I&M's internal energy and peak demand are expected to decrease at an average rate of 0.5% and 0.3% per year, respectively, through 2041.

Indiana IRP Stakeholder Process

For this IRP, I&M considered multiple sources of feedback, including comments in the Director's report, Stakeholder feedback, internal suggestions, as well as recommendations from the Siemens PTI consulting team. The Company engaged an experienced outside consultant, Siemens PTI, to bring their own experience, expertise, and collaboration tools to the stakeholder process. Both Siemens PTI and I&M promoted Stakeholder engagement during Stakeholder meetings despite the fact that all Stakeholder meetings had to be held virtually during this process due to the COVID pandemic.

The goal was a Stakeholder engagement process focused on promoting transparency in the IRP process, encouraging questions and feedback along the way, and converting feedback to actionable suggestions to incorporate into the IRP process. IRP Stakeholders included, but were not limited to, I&M residential, commercial, and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups and elected officials.

At the core of the process was a series of five Stakeholder Meeting Workshops. Stakeholder feedback was also received, and questions were answered via e-mail and with phone calls/meetings in between each session per request to ensure Stakeholder feedback was considered and incorporated in the development of the plan.

Also as part of the overall Stakeholder Engagement process, the Company reviewed the proposed All-Source RFP response documents with Stakeholders for additional feedback. Additionally a separate engagement process was developed for those "Technical Stakeholders" who desired to examine in more detail the underlying analysis performed during the IRP process.

Figure 2. Topic Covered in Stakeholder Meetings

Planning Process

The I&M 2021 IRP followed a 5-step structured and holistic approach, illustrated in Figure 3 to identify the Preferred Portfolio that best meets I&M's defined objectives over a wide range of potential future conditions and included an All-Source Informational RFP to include market-based pricing and a Market Potential Study (MPS) to inform the IRP process. This structured approach provided a comprehensive decision support tool to aid I&M in developing a long-term plan based on the current generation portfolio and the anticipated retirements of generation over the next twenty years. This long-term plan evaluates the need for additional resources and provides a resource portfolio that balances I&M's objectives.

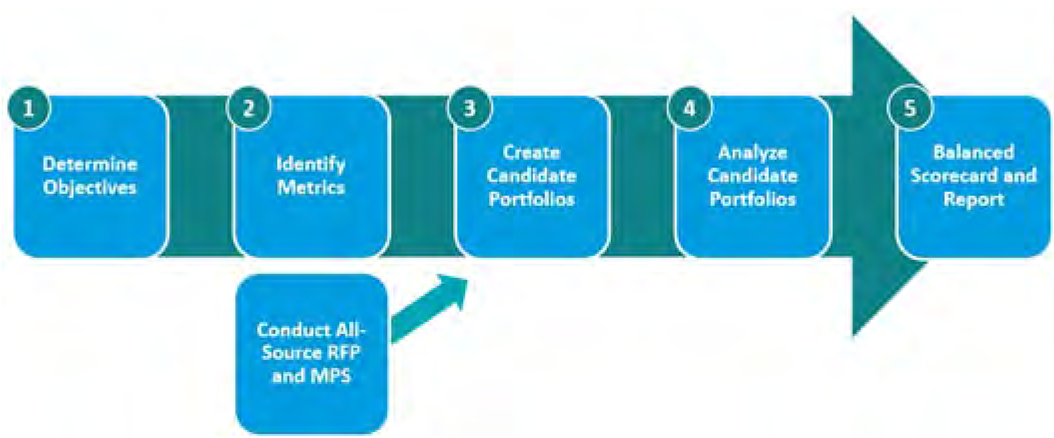


Figure 3: IRP Process

The 2021 IRP is designed to evaluate ongoing changes and uncertainties in the market. As a result, I&M's IRP objectives are based on the need for a resource strategy that provides support for a series of near-term resource decisions while providing important directional insight into the long-term resources needs and key considerations to maximize the long-term potential value to its customers and communities. To that end, I&M identified six objectives for the Preferred Portfolio in the 2021 IRP that align with customer and corporate priorities, including customer affordability, rate stability, market risk minimization, sustainability impact, reliability, and resource diversity. Table 1 provides more detail on these IRP objectives.

Table 1. I&M IRP Objectives

Objective Category	Objective	Objective Description
Affordability	Affordability	Meet energy and demand requirements of customers at an affordable cost that minimizes cost to serve load. Provide all customers with an affordable supply of energy.
	Rate Stability	Meet energy and demand requirements of customers with rate stability by providing a predictable, balanced, and diverse mix of energy resources designed to ensure costs do not vary greatly across alternative future market conditions or supply disruptions.
	Market Risk Minimization	Avoid overreliance on spot market for energy and capacity purchases and sales, which could introduce excess risk for customers.
Sustainability	Sustainability	Ability to produce energy in a way that proactively reduces pollution and impact on surrounding neighborhoods and ecosystem. Provide environmentally responsible power, leading to a low carbon future.
Reliability and Resource Diversification	Reliability	Ability to effectively produce and deliver the energy required by customers with minimal interruptions and consistent quality while maintaining compliance with PJM capacity obligations.
	Resource Diversity	Mitigate the risk of overreliance on one type of resource. Operational flexibility to back up the resource for resource types that could become operationally or economically eclipsed.

The IRP process complies with regulations and reliability requirements, while also quantifying risks introduced by the market and regulatory environments, the risk of over-reliance on imports and/or exports, and the risk of supply disruptions. The process considered numerous new resource options across multiple portfolios and evaluated these portfolios across a wide range of metrics.

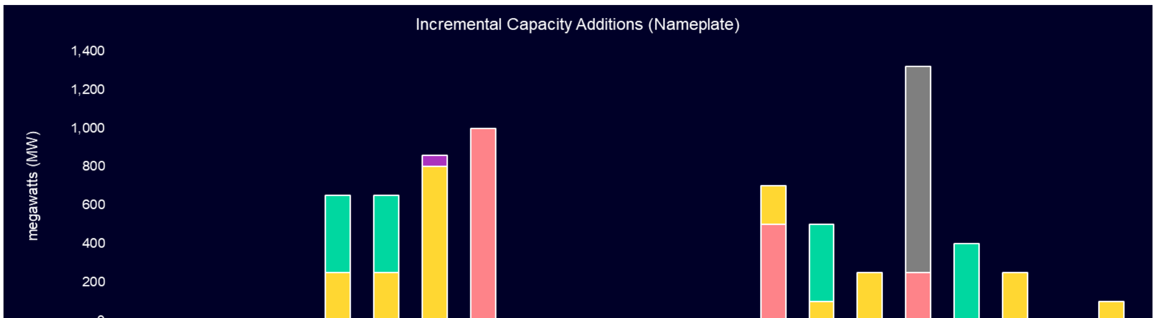
The electric utility industry is changing rapidly and is subject to a significant number of external factors that are largely outside its control. Examples include increased costs in business operations as well as the uncertainty in the timing and impacts that growth in renewable resources, customer-owned generation, and electrification of vehicles and the greater economy will have on load and resource requirements. Also, the focus of resource planning is shifting from the historical vertical approach to an integrated process that better coordinates and aligns the planning of generation, transmission, and distribution. As future IRPs are conducted, the Company expects continuous improvement in incorporating these dynamic and uncertain factors into the IRP process.

Summary of I&M's Resource Plan

I&M has prepared the Preferred Portfolio with a near-term plan, 2022 - 2028 and a long-term-indicative plan, 2029 – 2041. The near-term plan includes the resource additions that will be necessary for the Company to make from 2022 through 2028 and is inclusive of the Company's Short-Term Action Plan. The long-term-indicative plan includes the resource decisions that the Company will need to make from 2029 through the end of the planning period in 2041. The Company now has clarity regarding the Rockport Unit 1 retirement and the treatment of Rockport Unit 2 and the need for replacement capacity prior to 2028. Resource decisions beyond 2028 will ultimately be determined based on future decisions regarding the potential license extensions of the Cook Nuclear Plant, as well as other factors that will change over this time period. Because decisions have not been made regarding the license extensions and cost estimates have not been completed regarding the cost to extend the license, the Preferred Portfolio assumes Cook Unit 1 and 2 operations continue through 2034 and 2037, respectively.

With this significant decision regarding the potential license extensions at the Cook plant still uncertain, the Company was very intentional and thoughtful to structure the near-term plans in a manner that maintains optionality regarding the future decisions at the Cook Nuclear Plant. A significant consideration that the Company evaluated in the development of the Preferred Portfolio was the amount of energy being exported and potential future market risks. To maintain optionality regarding the future operations of the Cook Nuclear Plant, which is a significant emission-free energy producer, it was important for the Company to balance the need for near-term renewables and gas capacity additions with the energy position of the Company, while ensuring reliability. The resource additions included in the Company's Preferred Portfolio allow the Company to effectively begin its generation transition plan, replace the Rockport capacity, and maintain the option to extend the Cook Nuclear Plant Operating License. The Company's Preferred Portfolio achieves these three goals and performs well in the Balanced Scorecard against other Candidate Portfolios.

In addition to the existing resources, nameplate capacities of new supply-side resources in the Preferred Portfolio are shown in Figure 3 and include 1,600 MW of wind resources selected through 2038, 1,900 MW of stand-alone solar resources selected through 2041, the selection of hybrid paired solar + storage resources in 2027 of 60 MW storage / 300 MW Solar in 2027, 1,070 MW of Gas CC selected in 2037, and 1,750 MW of Gas CT resources through 2040.



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Wind	0	0	0	0	400	400	0	0	0	0	0	0	0	0	400	0	0	400	0	0	0
Storage	0	0	0	0	0	0	60	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	0	250	250	800	0	0	0	0	0	0	200	100	250	0	0	250	0	100
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	1,000	0	0	0	0	0	500	0	0	250	0	0	0	0

Figure 4. Incremental Capacity Additions (UCAP)

Figure 5 illustrates I&M's UCAP capacity position for the Preferred Portfolio and the PJM capacity obligation including existing resources for the periods when their capacity is available. The near-term plan includes both supply-side and demand-side resource additions in the Preferred Portfolio to meet the Company's near-term capacity needs. Resource additions through 2028 are sufficient from a capacity and energy needs perspective, with the exception of a short-term capacity deficit relative to the PJM minimum reserve requirement in PJM Planning Year 2024/2025. This deficit is currently expected to be approximately 314 MW, and will be filled with short-term PJM capacity purchases, as Rockport Unit 2 is transitioned out of the Company's regulated fleet and the Company transitions to a portfolio with more renewable resources. Short-term capacity needs are subject to further adjustments prior to the PJM Delivery Year based on evolving load forecasts and unit performance.

In the long-term plan between 2029 and 2041, utilizing an assumption for IRP modeling purposes that Cook Unit 1 and 2 will only operate until the end of the current license periods, the Preferred Portfolio includes an additional 800 MW of wind resources, 900 MW of solar, 1,070 MW of gas combined cycle, and 750 MW of gas peaking capacity. These resource additions will be modeled in future IRPs and updated as decisions are made regarding the Cook license extensions. The entire capacity plan is shown below:

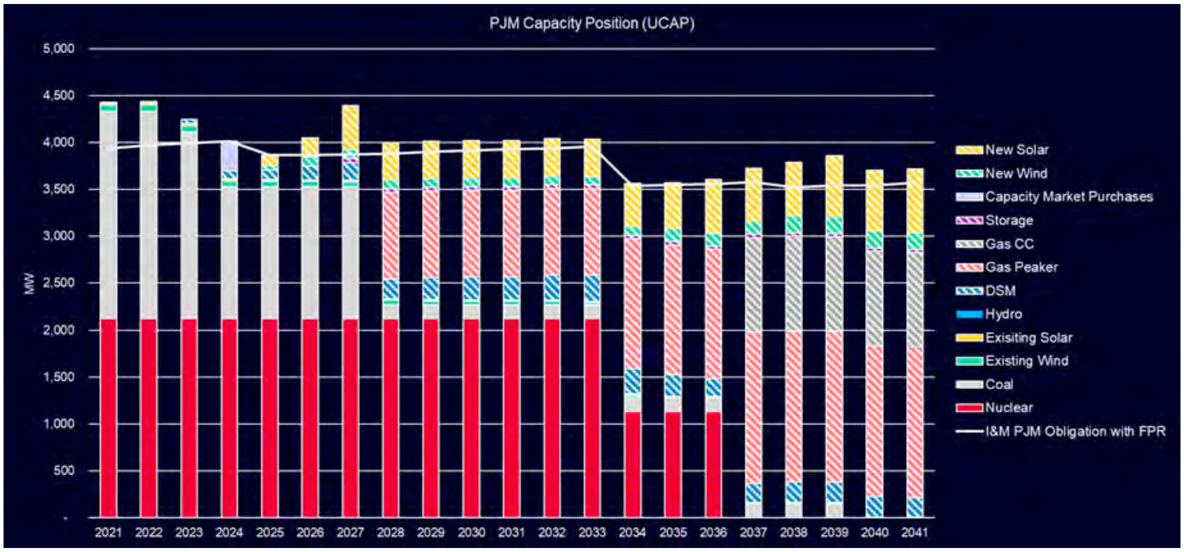


Figure 5. I&M's Preferred Portfolio - PJM Capacity Position (UCAP)

I&M conducted an expanded MPS that evaluated for a 20-year time horizon (2023-2042) the energy efficiency, demand response, and distributed energy resources potential separately for I&M's Indiana and Michigan jurisdictions. The MPS used the most granular load shape information available to improve the value realized from these measures. Energy Efficiency measure potential was developed using I&M's hourly load shape forecast data through an apportioning process based on the evaluation of which measures best aligned to load shapes according to I&M's customer segmentation and use profiles. This expanded approach in the MPS development stage helped improve energy efficiency measure attributes for the time-based value of these resources, thereby improving the level of energy efficiency benefits to be realized during the IRP modelling and optimization process.

Informed by the MPS, a diverse mix of energy efficiency bundles was selected across three vintages that peak at 247 MW in 2033. Furthermore, the Preferred Portfolio includes incremental resources of 121 MW of demand response, 71 MW of distributed energy resources and 116 MW of conservation voltage reduction, based on the Company's MPS and internal analysis.

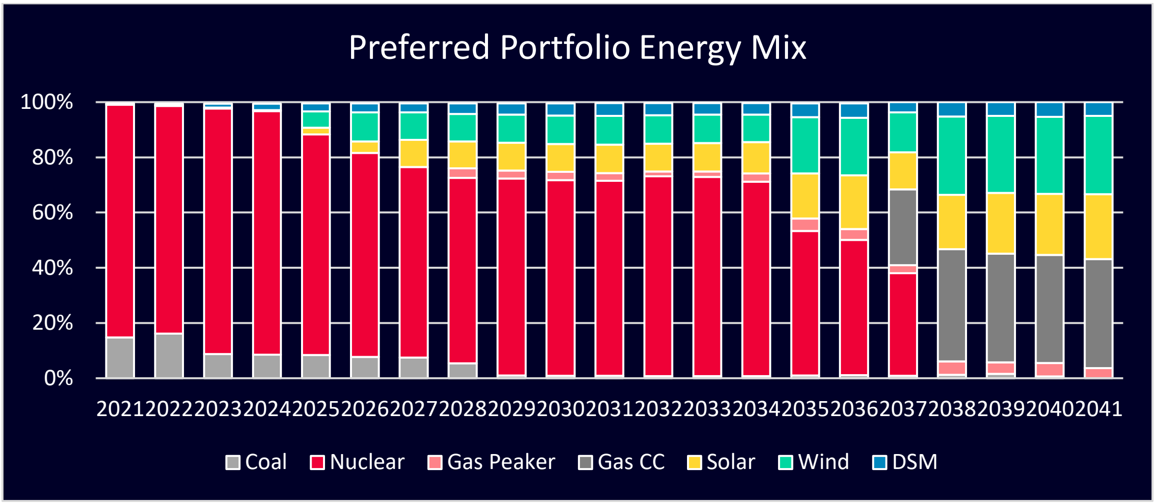


Figure 6: Preferred Portfolio Energy Mix

The forecasted energy mix by resource type contribution in the Preferred Portfolio over the planning period is illustrated in Figure 6. From an energy perspective, the Preferred Portfolio resources include the addition of energy rich renewable resources and DSM resources that serve to somewhat mitigate future risks related to fuel price uncertainty and potential carbon emission prices. Additionally, these resources include incremental dispatchable generating resources (CT) to support resource adequacy and reliability during the periods when renewable resources are not providing energy to meet the Company's load obligation.

I&M's Short Term Action Plan

The I&M IRP is regularly reviewed as new information becomes available. I&M intends to pursue the following activities for the IRP Short-Term Action Plan:

1. Continue the planning and regulatory actions necessary to implement additional cost-effective DSM programs in Indiana and Michigan consistent with this IRP that identified the potential for increased levels of cost-effective EE.
2. Obtain the capacity needed for the PJM Planning Year 2024/2025 deficit (currently estimated to be about 314 MW in this IRP).
3. Issue an All-Source RFP in the first quarter of 2022 to seek resources to satisfy the 2025 and 2026 needs (in-service by the end of 2024 and 2025), which the Preferred Portfolio identified as 800 MW of wind and 500 MW of solar.
4. Issue an All-Source RFP in 2023 or 2024 to satisfy identified needs, targeting 2027 and 2028 renewables, storage, and gas additions (in-service by the end of 2026 and 2027), totaling 800MW of solar, 60 MW of storage as a hybrid resource, and 1,000 MW of gas peaking.
5. Initiate efforts to evaluate Cook relicensing costs.
6. Adjust this action plan and future IRPs to reflect changing circumstances, as necessary.

Conclusion

This IRP incorporated an extensive and thorough process that engaged Stakeholders through five public Stakeholder meetings and tested several Scenarios and many different Portfolios to arrive at a Preferred Portfolio.

The Preferred Portfolio performs well across a range of metrics that were used in the Balanced Scorecard. The Preferred Portfolio is the best performing portfolio across multiple measures on the Balanced Scorecard and provides several additional benefits to I&M customers and Stakeholders, including the following:

Affordability and Rate Stability:

- The Preferred Portfolio is among the lowest reasonable cost portfolios measured on both a 20-year and 10-year cost to serve load metric. The only comparable portfolios are the Cook 2050+ life extensions portfolios, which do not include consideration of the capital investments required to extend the life of those facilities (will be evaluated further in future IRPs).
- The Preferred Portfolio has one of the lowest absolute values for the 95th percentile value of NPV cost to serve load. All portfolios share a similar upside risk. This translates into having one of the lowest risk of increases in cost across the portfolios.
- Resource type additions in the Preferred Portfolio are similar through 2028 to the portfolios that modeled Cook license extensions (Cook 2050+), resulting in a “no regrets” position for the next several years.
- The Preferred Portfolio includes dispatchable resources that can enhance opportunities for wholesale sales without overexposure to market risks.
- The Preferred Portfolio takes advantage of existing tax incentives for new wind, solar and hybrid solar resources.
- The Preferred Portfolio requires the lowest capital requirements during the near-term planning period, which also lowers the risk associated with the availability of acquiring the necessary resources.

Market Risk

- The Preferred Portfolio mitigates overreliance on market purchases and sales for capacity and energy throughout the forecast horizon.
- The Preferred Portfolio requires short-term PJM capacity purchases for capacity in 2024 to replace Rockport Unit 2 capacity.
- Market purchases and sales of energy are reasonable and there is less reliance on the spot energy market, with the Preferred Portfolio averaging 7.2% for purchases and 19.8% for sales over the forecast horizon.
- The Preferred Portfolio results in small amounts of surplus capacity over the forecast period

- The Preferred Portfolio avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

Sustainability:

- The Preferred Portfolio leads to a lower carbon future, achieving 76% reduction by 2041, when including CO_2 emissions for short-term and spot market purchases, from 2005 levels that did not include CO_2 emissions assumptions from short-term and spot market purchases. Excluding short-term and spot market purchase emissions estimates, the Preferred Portfolio realizes CO_2 emissions reductions of 82% by 2041.
- The Preferred Portfolio includes a substantial amount of renewable resources as it continues to transform its fleet.
- The Preferred Portfolio maintains the optionality for the Cook License Extensions which maintains the opportunity to extend the operations of a significant emission-free resource.
- The Preferred Portfolio provides potential opportunities for natural gas conversion to hydrogen fuel later in the planning period.
- The Preferred Portfolio significantly reduces the reliance on coal fired generation by 2029.

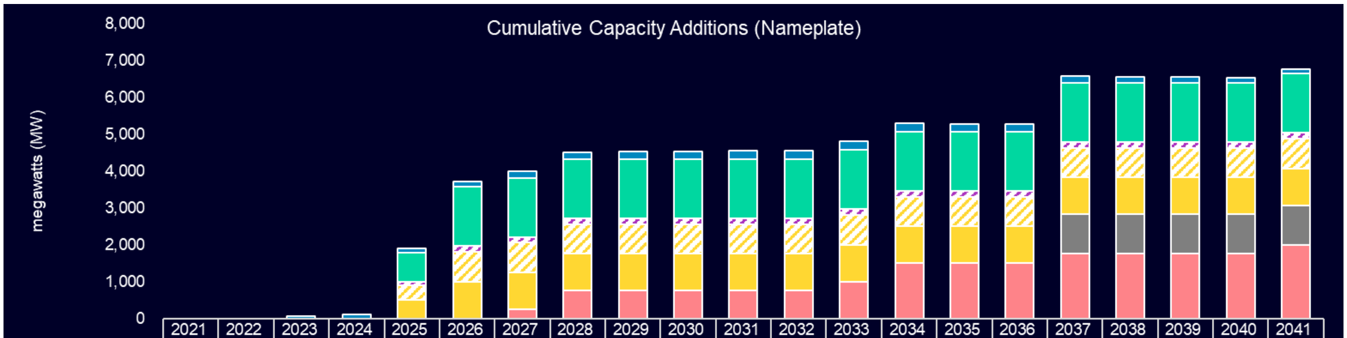
Reliability and Resource Diversity:

- The Preferred Portfolio includes additions that when added to the Company's current resources, provides a more diversified portfolio of supply-side and demand-side resources that will allow the Company to optimize the use of each resource type to ensure the reliable supply of electricity while also maintaining PJM capacity requirements and supporting resource adequacy.
- The Combustion Turbine (CT) resources provide flexible, fast ramping capabilities and can help mitigate risks associated with intermittent renewable resource additions.
- The Preferred Portfolio manages the reliance on market purchases and sales for capacity and energy purposes. In addition, it avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and eight unique fuel types.

The Preferred Portfolio manages the reliance on either market purchases or sales for capacity or energy purposes. In addition, it avoids reliance on any single resource or fuel type, with potentially over 60 unique resources and 8 unique fuel types and offers I&M significant flexibility should future conditions differ considerably from the assumptions underpinning the Preferred Portfolio.

Exhibit C Case and Scenario Results

Exhibit C-1: Portfolio Name: Reference (Original)



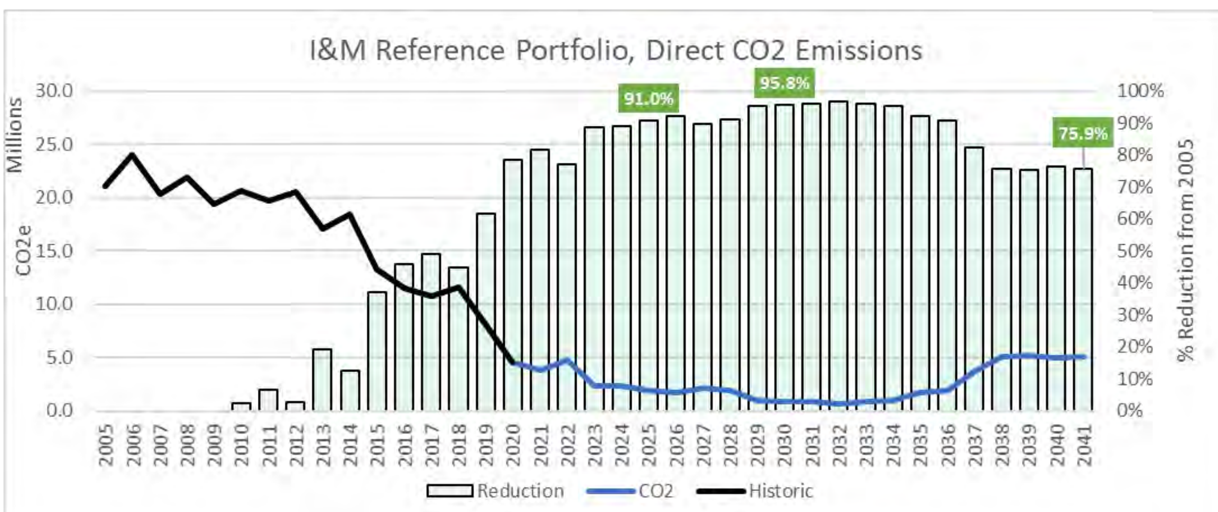
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	112	144	172	189	210	223	234	241	247	235	213	197	182	168	157	149	124
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750	750	1,000	1,500	1,500	1,500	1,750	1,750	1,750	1,750	2,000
Total	0	0	50	96	1,892	3,704	3,982	4,499	4,520	4,533	4,544	4,551	4,807	5,295	5,273	5,257	6,562	6,548	6,537	6,529	6,754

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,271	189,516	48	61,145	80,946	124,407	438,441
2022	131,232	222,721	59	53,884	81,824	178,018	504,090
2023	111,965	241,999	34	59,706	48,661	126,599	491,638
2024	114,030	253,214	45	59,600	47,791	127,061	506,154
2025	112,209	556,560	53	14,817	128,262	102,424	657,791
2026	117,053	878,520	52	(27,327)	252,326	84,752	800,714
2027	135,064	897,382	49	(27,912)	271,132	92,216	825,667
2028	144,001	835,000	16,699	(30,584)	322,977	90,680	732,652
2029	131,925	811,464	7,326	(27,121)	291,685	70,670	702,140
2030	129,848	802,042	6,304	(28,408)	274,897	62,443	696,986
2031	121,561	774,530	5,750	(31,315)	244,374	64,385	689,846
2032	124,378	760,520	4,772	(26,756)	254,734	61,368	669,141
2033	128,017	767,443	5,766	(28,340)	243,203	48,045	677,383
2034	127,726	785,432	8,767	(28,159)	314,380	41,291	619,976
2035	86,388	707,086	9,072	47,723	96,032	59,892	813,766
2036	81,416	693,649	8,987	45,309	83,926	78,558	823,408
2037	221,685	831,780	41,404	61,234	265,473	11,322	900,482
2038	169,570	748,099	43,047	31,277	52,294	111,624	1,051,323
2039	171,587	730,178	44,082	31,044	54,864	108,296	1,030,323
2040	165,528	711,558	42,600	30,906	46,986	119,167	1,022,773
2041	171,512	703,430	45,688	30,859	56,398	118,061	1,014,281
						NPV $B	**$ 7.30**

Stochastic Range IRP Cost to Serve Load (NPV $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,550,712	7,638,924	7,174,575	6,807,873	6,396,077
NPV (2021-2030)	4,900,444	4,457,193	4,224,769	4,029,736	3,821,922
CAGR (2022-2030)	6.12%	5.13%	4.12%	3.08%	1.48%

Stochastic Range IRP Cost to Serve Load ($,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,476	445,134	437,065	428,671	421,134
2022	546,926	514,808	498,451	487,077	476,845
2023	552,133	505,873	486,499	470,872	450,176
2024	580,381	528,181	497,586	479,138	458,661
2025	743,350	686,931	650,364	621,571	582,905
2026	917,107	851,590	803,123	755,507	691,899
2027	946,035	874,444	824,354	774,793	706,720
2028	879,914	784,297	730,793	673,819	576,746
2029	879,218	758,484	695,347	625,507	548,532
2030	876,164	756,155	695,663	626,163	541,817
2031	896,781	742,595	672,747	624,350	542,270
2032	863,477	727,228	658,660	592,955	506,441
2033	870,328	728,403	670,404	605,607	507,633
2034	825,869	691,200	615,111	539,969	451,394
2035	1,003,113	865,811	791,207	742,260	693,078
2036	1,007,764	876,928	804,599	759,163	688,706
2037	1,101,184	946,887	888,368	826,353	754,662
2038	1,271,572	1,116,478	1,017,877	972,963	906,147
2039	1,248,102	1,083,929	1,005,320	956,136	889,087
2040	1,285,496	1,075,912	995,064	934,181	859,631
2041	1,220,873	1,074,828	989,443	941,348	867,445



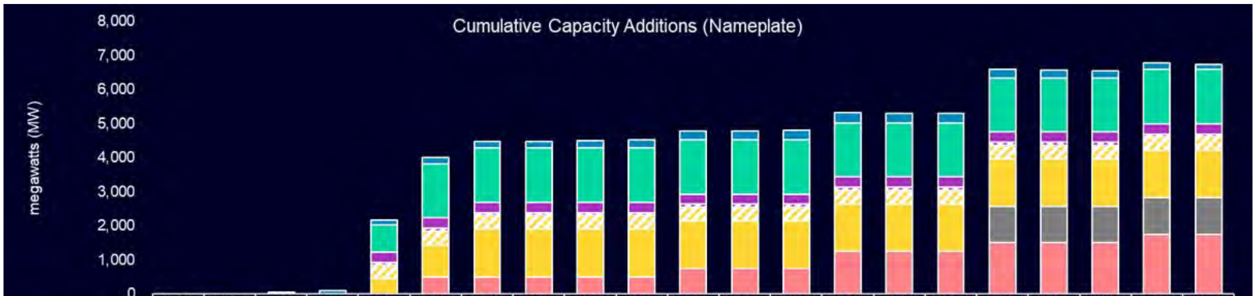
Direct and Lifecycle Emissions (tons CO_2), Stochastic

Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,288,302	593,074	3,881,376	3,689,955
2022	3,316,800	1,491,801	4,808,601	4,616,224
2023	1,700,556	713,037	2,413,594	2,333,940
2024	1,604,358	717,650	2,322,008	2,246,984
2025	1,674,176	557,572	2,231,748	2,210,291
2026	1,683,291	238,291	1,921,582	1,948,750
2027	1,923,804	208,947	2,132,751	2,243,589
2028	2,107,020	244,839	2,351,859	1,605,478
2029	1,191,191	214,944	1,406,135	1,756,660
2030	1,034,606	257,342	1,291,948	1,623,259
2031	931,595	348,998	1,280,593	1,597,097
2032	803,138	258,611	1,061,748	1,363,743
2033	883,320	352,573	1,235,893	1,543,513
2034	1,128,919	186,566	1,315,485	1,680,460
2035	1,167,023	991,971	2,158,994	2,549,272
2036	1,147,102	1,212,125	2,359,227	2,776,447
2037	3,865,740	170,117	4,035,857	5,347,449
2038	3,916,618	1,327,267	5,243,885	6,586,721
2039	4,058,104	1,217,233	5,275,337	6,654,828
2040	3,668,364	1,338,488	5,006,853	6,341,131
2041	3,642,442	1,383,251	5,025,693	6,371,141

2005 Baseline Direct I&M Emissions (tons CO2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-2: Portfolio Name: Rockport 1 - 2024



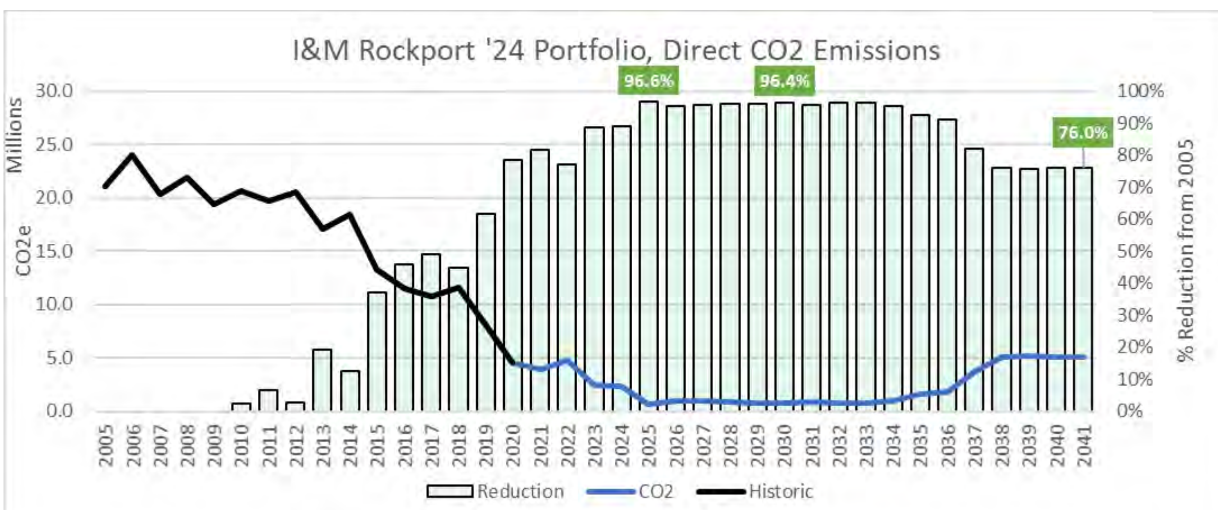
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	139	168	193	208	226	242	256	262	276	286	282	281	253	229	208	177	140
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Hybrid Storage	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Hybrid Solar	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Solar	0	0	0	0	450	950	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	500	500	500	500	500	750	750	750	1,250	1,250	1,250	1,500	1,500	1,500	1,750	1,750
Total	0	0	50	96	2,169	3,998	4,473	4,488	4,506	4,522	4,786	4,792	4,806	5,316	5,312	5,311	6,603	6,579	6,558	6,777	6,740

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,301	189,516	48	61,146	81,062	124,460	438,410
2022	131,293	222,721	58	53,887	81,857	177,968	504,071
2023	112,340	234,403	35	59,726	49,139	126,582	483,945
2024	113,209	242,001	44	59,570	47,816	128,842	495,843
2025	87,317	586,927	0	13,426	93,054	104,542	699,157
2026	109,622	858,029	13	(29,570)	214,924	84,981	808,151
2027	114,098	919,508	9	(29,094)	239,968	92,704	857,257
2028	119,022	812,696	5,080	(31,638)	281,067	92,393	716,232
2029	125,083	800,812	5,279	(27,300)	284,452	71,018	690,123
2030	124,368	792,907	4,546	(28,553)	270,304	62,820	685,626
2031	123,892	787,253	6,422	(31,256)	251,774	64,336	698,167
2032	126,507	773,001	5,407	(26,702)	261,836	61,410	677,355
2033	125,596	762,724	4,768	(28,414)	243,396	48,183	669,294
2034	126,517	788,271	8,166	(28,206)	318,579	41,176	616,732
2035	84,716	710,954	8,357	47,667	97,173	57,982	812,210
2036	80,485	697,106	8,442	45,272	86,660	75,797	819,977
2037	223,076	821,448	41,552	61,342	275,317	10,914	881,705
2038	170,454	737,967	43,028	31,357	54,434	107,427	1,036,616
2039	172,234	720,303	43,967	31,117	56,436	104,657	1,016,405
2040	171,040	723,057	43,990	31,124	53,654	116,034	1,031,591
2041	172,883	693,584	45,741	30,983	56,000	115,518	1,004,108
						NPV $B	**$ 7.30**

Stochastic Range IRP Cost to Serve Load ($,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,467	444,836	436,836	428,611	421,083
2022	547,158	515,006	498,417	486,799	476,949
2023	544,504	498,121	478,971	463,313	443,053
2024	570,874	518,263	486,320	468,042	448,932
2025	790,538	727,565	692,445	664,936	633,458
2026	920,135	844,324	806,101	766,333	719,833
2027	977,449	903,664	849,125	809,441	745,535
2028	874,399	768,558	708,723	653,878	566,750
2029	869,410	749,359	681,637	612,494	536,406
2030	866,765	746,643	678,529	616,783	529,120
2031	907,246	753,432	682,815	630,836	549,423
2032	874,043	741,293	660,610	599,285	513,264
2033	865,298	725,169	664,556	596,646	498,302
2034	821,660	692,760	611,234	541,252	438,640
2035	1,000,571	864,118	789,925	742,040	686,898
2036	1,006,272	874,187	801,742	750,733	687,843
2037	1,086,459	929,123	871,320	806,024	740,880
2038	1,255,955	1,101,347	1,003,554	959,435	891,602
2039	1,232,511	1,066,926	992,720	942,551	876,484
2040	1,288,835	1,087,278	1,004,772	942,795	867,236
2041	1,210,669	1,066,787	980,785	935,144	857,789

Stochastic Range IRP Cost to Serve Load (NPV $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,585,315	7,646,824	7,162,424	6,791,435	6,403,657
NPV (2021-2030)	4,921,791	4,487,243	4,234,256	4,047,005	3,859,868
CAGR(2022-2030)	6.02%	4.85%	3.93%	2.85%	1.05%



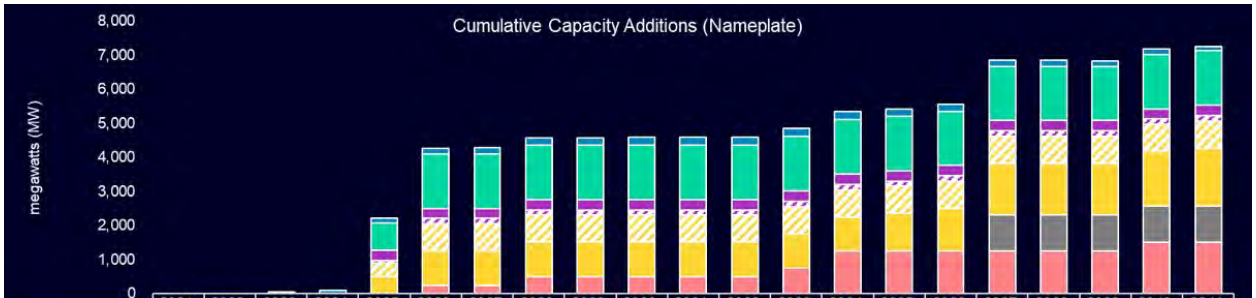
Direct And Lifecycle Emissions (tons CO_2), Stochastic

Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e**[1]
2021	3,281,135	594,076	3,875,211	3,684,394
2022	3,317,585	1,493,279	4,810,864	4,618,413
2023	1,701,951	713,571	2,415,523	2,335,749
2024	1,566,831	741,151	2,307,982	2,236,310
2025	385,949	322,167	708,117	889,196
2026	909,996	54,268	964,263	1,310,300
2027	853,147	84,773	937,920	1,325,471
2028	713,436	126,521	839,957	1,223,480
2029	725,775	91,245	817,020	1,197,041
2030	628,542	125,765	754,307	1,123,366
2031	743,187	161,569	904,756	1,289,402
2032	641,560	128,271	769,831	1,143,963
2033	608,016	179,329	787,345	1,150,951
2034	862,557	80,705	943,262	1,341,912
2035	899,898	697,320	1,597,217	1,991,510
2036	891,569	945,812	1,837,381	2,230,823
2037	3,632,500	132,458	3,764,958	5,053,844
2038	3,709,711	1,345,520	5,055,231	6,363,684
2039	3,840,866	1,310,703	5,151,569	6,467,333
2040	3,589,828	1,455,607	5,045,435	6,335,787
2041	3,547,177	1,522,980	5,070,157	6,358,211

2005 Baseline Direct I&M Emissions (tons CO2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-3: Portfolio Name: Rockport 1 - 2025



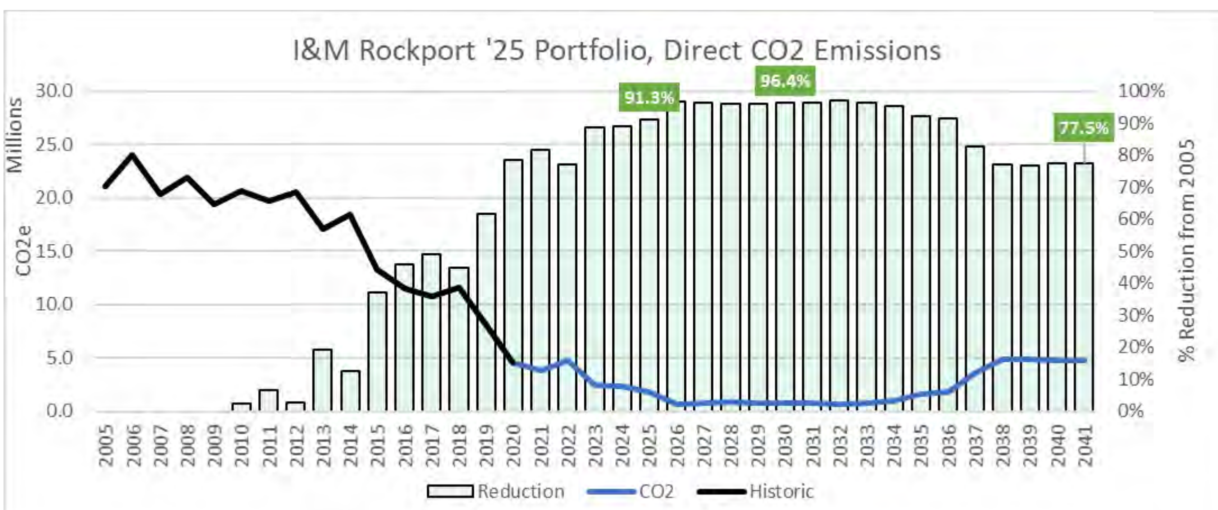
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EE	0	0	50	96	139	167	191	204	221	231	241
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	300	300	300	300	300	300	300
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	250	250	500	500	500	500
Total	0	0	50	96	2,219	4,277	4,301	4,564	4,581	4,591	4,601

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	243	248	235	213	197	182	169	157	149	124
Wind	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	300	300	300	300	300	300	300	300	300	300
Hybrid Storage	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	800	800	800	800	800	800	800	800	800	800
Solar	1,000	1,000	1,000	1,100	1,250	1,500	1,500	1,500	1,600	1,700
Gas CC	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	500	750	1,250	1,250	1,250	1,250	1,250	1,250	1,500	1,500
Total	4,603	4,858	5,345	5,423	5,557	6,862	6,849	6,837	7,179	7,254

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,280	189,516	48	61,145	80,964	124,421	438,446
2022	131,250	222,721	58	53,884	81,693	177,883	504,103
2023	112,237	241,999	34	59,721	49,036	126,589	491,539
2024	114,040	251,190	45	59,599	47,609	126,980	504,240
2025	110,383	599,681	51	14,734	129,159	103,463	699,143
2026	100,960	929,264	7	(28,275)	227,686	84,879	859,150
2027	107,044	924,829	4	(29,292)	231,934	93,123	863,774
2028	118,949	840,229	5,060	(31,640)	280,723	92,380	744,002
2029	125,060	827,652	5,275	(27,301)	284,041	70,994	717,322
2030	124,365	817,856	4,544	(28,553)	269,905	62,799	710,947
2031	117,699	789,987	4,332	(31,424)	242,004	64,665	702,779
2032	121,268	775,636	3,639	(26,848)	253,100	61,620	681,924
2033	125,597	782,233	4,742	(28,414)	242,134	48,268	690,151
2034	126,476	799,909	8,156	(28,207)	315,128	41,350	631,944
2035	84,685	733,096	8,346	48,011	98,800	58,841	833,887
2036	80,457	736,851	8,473	46,136	94,234	75,043	852,219
2037	218,113	882,547	40,056	62,916	291,378	10,760	921,722
2038	165,028	797,877	41,403	32,894	65,338	101,366	1,073,884
2039	166,290	778,696	42,174	32,633	67,287	98,536	1,051,715
2040	165,661	791,813	42,404	33,001	69,026	105,650	1,069,504
2041	166,442	772,642	43,783	33,147	73,910	103,914	1,046,237
						NPV $B	$ 7.49

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,446	444,983	437,049	428,712	421,002
2022	547,148	514,978	498,517	486,893	476,846
2023	552,095	505,841	486,432	470,912	450,568
2024	577,668	525,994	494,821	477,293	456,264
2025	786,388	728,428	692,061	663,169	625,680
2026	962,509	900,388	859,198	815,515	765,567
2027	984,313	910,136	855,312	815,728	749,649
2028	901,805	796,527	736,857	681,635	594,639
2029	896,069	776,405	708,753	639,463	563,793
2030	892,257	771,806	704,087	641,993	554,596
2031	911,121	758,092	686,775	636,067	554,549
2032	879,235	745,230	666,224	603,471	517,667
2033	885,852	745,565	685,026	617,501	519,740
2034	837,347	707,587	626,025	557,098	454,054
2035	1,022,215	885,673	811,653	763,676	708,310
2036	1,038,579	907,640	835,972	783,866	720,422
2037	1,125,966	971,126	911,269	845,497	777,790
2038	1,293,333	1,133,881	1,043,802	996,717	933,237
2039	1,264,584	1,099,502	1,028,970	977,962	910,818
2040	1,328,576	1,129,026	1,038,646	986,441	913,953
2041	1,237,477	1,107,598	1,023,236	977,725	903,854

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,756,321	7,833,886	7,337,956	6,970,844	6,576,541
NPV (2021-2030)	5,017,107	4,574,101	4,326,143	4,133,839	3,952,800
CAGR(2022-2030)	6.40%	5.32%	4.41%	3.37%	1.66%



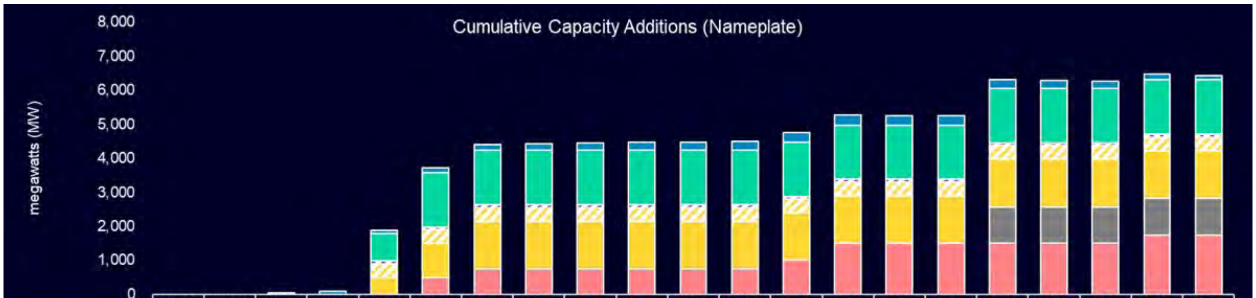
Direct and Lifecycle Emissions (tons CO_2), Stochastic

Year	Direct I&M	Imports (CO_2e)	Total Direct + Imports	Total Lifecycle GHG CO_2e[1]
2021	3,280,348	593,588	3,873,936	3,683,166
2022	3,315,794	1,492,041	4,807,835	4,615,573
2023	1,696,776	713,732	2,410,508	2,331,177
2024	1,603,455	717,658	2,321,113	2,246,162
2025	1,531,215	307,356	1,838,571	1,923,419
2026	656,834	53,286	710,120	1,073,836
2027	661,864	91,582	753,446	1,114,319
2028	711,473	126,446	837,919	1,221,183
2029	724,880	91,108	815,987	1,195,924
2030	628,324	125,593	753,917	1,122,950
2031	579,583	165,792	745,375	1,107,189
2032	500,363	131,331	631,695	986,108
2033	607,889	180,508	788,397	1,151,988
2034	861,860	82,975	944,835	1,343,381
2035	898,991	707,831	1,606,822	2,012,758
2036	890,136	934,170	1,824,306	2,247,065
2037	3,510,479	134,060	3,644,539	4,973,848
2038	3,579,362	1,258,265	4,837,627	6,183,776
2039	3,697,646	1,221,988	4,919,634	6,271,216
2040	3,465,388	1,314,421	4,779,808	6,119,797
2041	3,395,376	1,357,573	4,752,948	6,097,355

2005 Baseline Direct I&M Emissions (tons CO2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-4: Portfolio Name: Rockport 1 - 2026



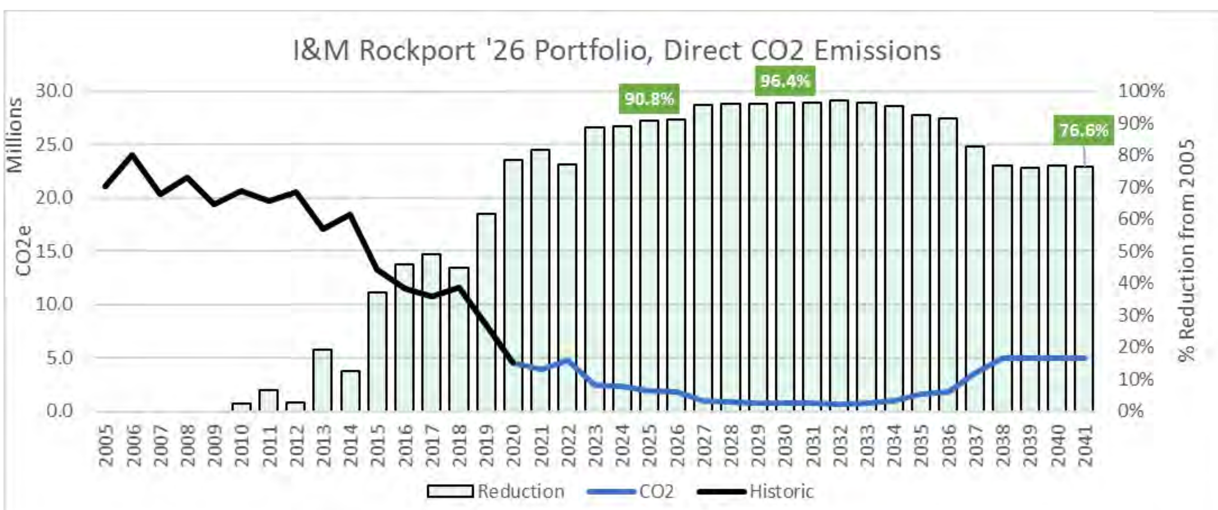
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	113	146	175	194	216	235	251	261	276	286	282	281	253	229	208	176	140
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Hybrid Solar	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Solar	0	0	0	0	500	1,000	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,400
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	500	750	750	750	750	750	750	1,000	1,500	1,500	1,500	1,500	1,500	1,500	1,750	1,750
Total	0	0	50	96	1,893	3,726	4,405	4,424	4,446	4,465	4,481	4,491	4,756	5,266	5,262	5,261	6,303	6,279	6,258	6,476	6,440

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,390	189,516	48	61,150	81,026	124,345	438,424
2022	131,253	222,721	58	53,884	81,808	178,001	504,110
2023	112,204	241,999	34	59,718	48,948	126,570	491,574
2024	114,045	253,214	45	59,599	47,659	126,946	506,184
2025	112,904	554,960	53	14,850	130,120	102,605	655,242
2026	132,385	850,288	52	(28,281)	250,338	84,934	789,039
2027	121,016	923,360	13	(28,900)	246,429	92,555	861,614
2028	127,893	817,099	7,547	(31,418)	292,749	92,233	720,227
2029	133,904	805,635	7,865	(27,074)	296,661	70,727	693,924
2030	132,014	798,187	6,773	(28,355)	280,910	62,467	689,939
2031	123,950	771,354	6,440	(31,254)	251,304	64,405	682,883
2032	126,549	758,051	5,420	(26,701)	261,752	61,411	662,545
2033	130,528	769,961	6,282	(28,282)	250,670	47,959	675,590
2034	131,063	795,976	9,740	(28,079)	325,629	41,171	623,511
2035	89,671	719,037	9,939	47,798	104,534	57,697	819,261
2036	85,362	705,623	10,088	45,400	93,439	75,107	827,536
2037	223,156	809,528	41,581	61,345	275,334	11,011	869,854
2038	170,535	726,845	43,050	31,360	54,363	107,362	1,025,604
2039	172,397	710,058	44,006	31,124	56,404	104,547	1,006,291
2040	171,179	713,397	44,029	31,125	53,495	115,919	1,022,155
2041	172,929	684,982	45,757	30,984	55,819	115,506	995,734
						NPV $B	**$ 7.27**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,535	444,853	437,279	428,668	420,999
2022	547,115	514,948	498,400	486,984	476,878
2023	552,078	505,299	486,442	470,828	450,641
2024	580,364	527,875	496,861	479,322	458,289
2025	740,723	684,990	647,585	619,222	580,389
2026	889,485	833,866	789,584	745,724	692,782
2027	980,493	909,465	853,116	813,605	749,340
2028	873,676	772,590	714,835	659,094	564,085
2029	871,160	752,615	683,345	617,029	540,188
2030	871,577	753,162	684,359	618,758	533,051
2031	891,081	739,024	667,057	614,073	533,143
2032	858,295	726,463	646,962	583,993	497,408
2033	871,165	731,908	670,773	603,364	499,400
2034	845,013	698,975	615,456	547,561	440,754
2035	1,026,201	871,550	796,639	743,613	693,759
2036	1,019,929	884,749	808,553	757,135	695,114
2037	1,073,611	921,213	857,814	792,465	727,155
2038	1,249,248	1,092,169	990,689	946,666	878,751
2039	1,229,913	1,054,679	980,811	930,558	864,437
2040	1,292,385	1,078,400	995,190	931,275	855,644
2041	1,209,380	1,056,197	970,017	924,668	847,192

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,539,711	7,608,982	7,126,290	6,747,711	6,360,193
NPV (2021-2030)	4,893,635	4,459,483	4,213,998	4,022,269	3,836,395
CAGR(2022-2030)	6.10%	4.97%	4.04%	2.96%	1.18%



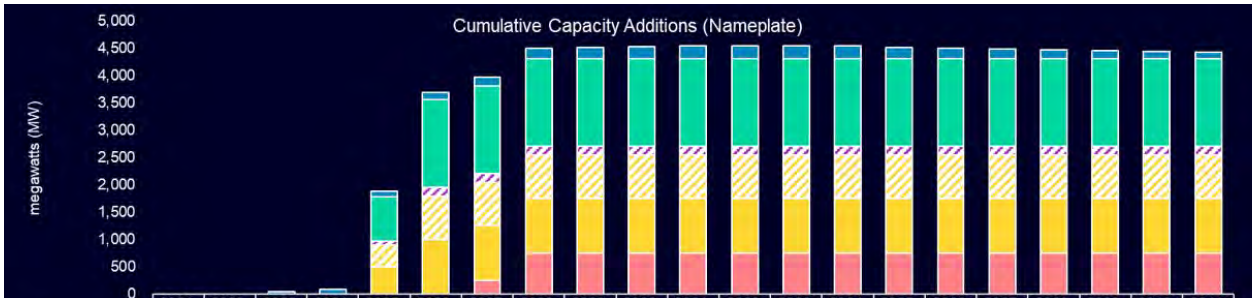
Direct and Lifecycle Emissions (tons CO_2), Stochastic

Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	Total **Lifecycle GHG CO_2e**[1]
2021	3,285,838	592,443	3,878,281	3,687,085
2022	3,316,024	1,493,541	4,809,565	4,617,282
2023	1,695,321	713,388	2,408,708	2,329,516
2024	1,603,790	718,025	2,321,815	2,246,842
2025	1,650,732	296,075	1,946,807	2,021,044
2026	1,789,698	53,787	1,843,485	2,344,224
2027	854,349	82,556	936,904	1,536,995
2028	713,887	127,175	841,063	1,466,783
2029	727,171	88,196	815,367	1,443,387
2030	630,405	122,562	752,967	1,338,082
2031	580,488	161,994	742,483	1,291,598
2032	501,449	129,381	630,830	1,146,337
2033	609,893	176,155	786,048	1,293,942
2034	862,470	79,937	942,407	1,481,930
2035	899,870	692,863	1,592,733	2,132,433
2036	891,486	936,637	1,828,123	2,362,977
2037	3,522,956	133,642	3,656,598	5,057,939
2038	3,599,690	1,342,608	4,942,298	6,363,188
2039	3,720,360	1,307,237	5,027,598	6,467,704
2040	3,488,701	1,452,494	4,941,195	6,336,091
2041	3,423,778	1,520,906	4,944,685	6,357,560

2005 Baseline Direct I&M Emissions (tons CO2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-5: Portfolio Name: Cook 2050+

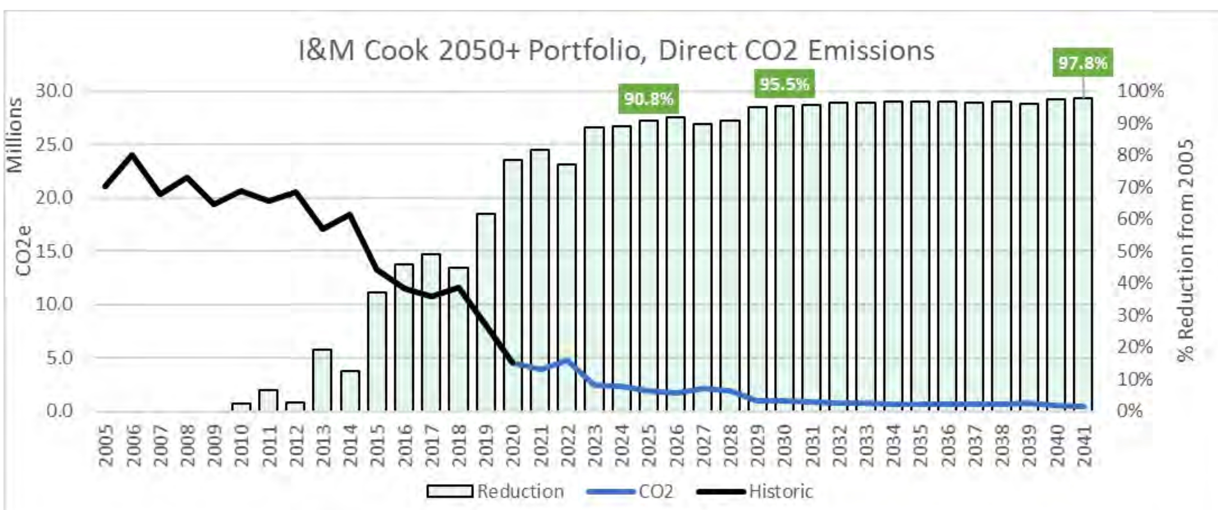


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	112	144	172	189	210	223	234	241	247	235	213	197	182	168	149	141	117
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750	750	750	750	750	750	750	750	750	750	750
Total	0	0	50	96	1,892	3,704	3,982	4,499	4,520	4,533	4,544	4,551	4,557	4,545	4,523	4,507	4,492	4,478	4,459	4,451	4,427

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	**Fixed Cost**	**Emissions Cost**	**Variable O&M**	**Energy Export Revenue**	**Energy Import Cost**	**Cost to Serve Load**
2021	144,307	189,516	48	61,146	81,115	124,522	438,425
2022	131,293	222,721	58	53,886	81,742	177,877	504,094
2023	112,216	249,618	34	59,720	48,997	126,594	499,181
2024	114,065	260,833	45	59,599	47,641	126,932	513,828
2025	112,894	564,179	53	14,850	130,088	102,582	664,461
2026	117,660	886,139	54	(27,298)	255,124	84,935	806,355
2027	136,084	900,239	50	(27,875)	274,081	92,344	826,761
2028	146,702	836,905	17,573	(30,504)	328,964	90,522	732,057
2029	133,873	813,369	7,858	(27,075)	296,389	70,715	701,879
2030	132,038	803,947	6,778	(28,355)	280,540	62,433	696,064
2031	123,964	776,435	6,446	(31,254)	250,796	64,404	688,489
2032	126,560	762,425	5,423	(26,701)	260,952	61,435	667,756
2033	125,625	746,102	4,750	(28,413)	242,096	48,296	654,122
2034	117,322	721,993	4,996	(28,463)	300,652	41,374	556,195
2035	121,670	714,203	4,755	76,680	310,673	7,669	612,791
2036	117,580	700,863	4,767	74,396	285,987	10,661	621,791
2037	121,517	689,077	4,565	76,923	302,937	8,418	596,262
2038	120,133	681,524	4,240	76,948	303,861	7,743	585,800
2039	120,893	662,014	4,569	76,540	307,387	8,517	564,372
2040	119,516	649,842	3,898	76,960	294,711	6,803	561,481
2041	120,541	622,425	4,989	75,338	289,942	7,923	537,029
						NPV $B	**$ 6.57**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,476	444,839	436,958	428,661	420,939
2022	547,116	514,804	498,478	487,066	476,824
2023	559,524	513,505	494,055	478,567	458,279
2024	587,278	535,570	504,746	486,943	465,936
2025	750,317	693,468	656,901	628,680	589,782
2026	919,817	857,406	808,439	761,524	700,254
2027	949,633	877,597	824,043	772,898	702,719
2028	885,596	786,149	727,654	669,453	571,697
2029	879,935	760,921	692,188	625,585	549,088
2030	877,671	757,507	689,008	626,209	540,674
2031	897,400	743,764	673,053	620,706	540,154
2032	863,670	731,542	651,131	589,810	503,694
2033	849,879	709,662	649,680	581,937	483,384
2034	760,200	630,586	551,905	479,474	383,765
2035	816,256	677,620	600,492	533,214	457,865
2036	815,099	691,227	622,477	539,077	456,520
2037	800,525	673,674	591,638	523,034	412,462
2038	779,742	654,487	579,462	514,693	407,623
2039	760,930	631,545	559,755	491,152	375,454
2040	751,306	633,933	555,135	489,673	394,099
2041	737,341	610,977	535,391	454,929	376,415

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	7,896,458	6,965,985	6,454,927	6,058,013	5,587,851
NPV (2021-2030)	4,928,348	4,472,609	4,234,868	4,052,377	3,853,541
CAGR(2022-2030)	6.19%	5.04%	4.16%	3.05%	1.36%

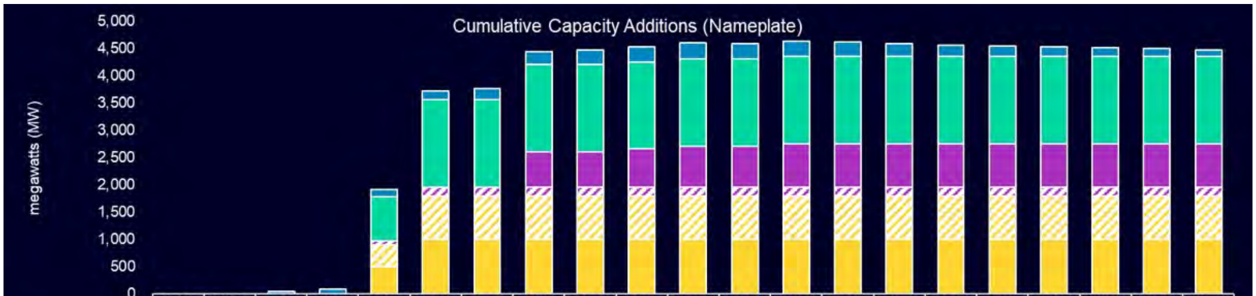


Direct Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports(CO_2e)**	Total Direct+ **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,281,421	595,076	3,876,498	3,685,654
2022	3,317,665	1,491,860	4,809,525	4,617,092
2023	1,695,822	713,653	2,409,475	2,330,239
2024	1,604,716	717,781	2,322,496	2,247,429
2025	1,650,220	295,730	1,945,951	2,020,232
2026	1,658,558	56,786	1,715,344	1,931,928
2027	2,098,024	82,045	2,180,069	2,412,981
2028	1,853,545	110,365	1,963,910	2,293,905
2029	943,606	88,145	1,031,751	1,442,200
2030	820,316	122,162	942,478	1,338,284
2031	745,269	162,058	907,327	1,292,247
2032	643,023	129,836	772,860	1,147,180
2033	608,724	180,400	789,124	1,152,817
2034	614,759	82,590	697,349	1,061,372
2035	592,601	99,531	692,133	1,044,099
2036	588,552	100,792	689,344	1,041,045
2037	605,703	110,655	716,358	1,067,604
2038	575,860	113,685	689,545	1,036,768
2039	689,599	101,369	790,968	1,147,477
2040	441,495	100,153	541,647	879,362
2041	361,783	103,587	465,370	802,255

2005 Baseline Direct I&M Emissions (tons CO2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-6: Portfolio Name: Cook 2050+ and No Gas

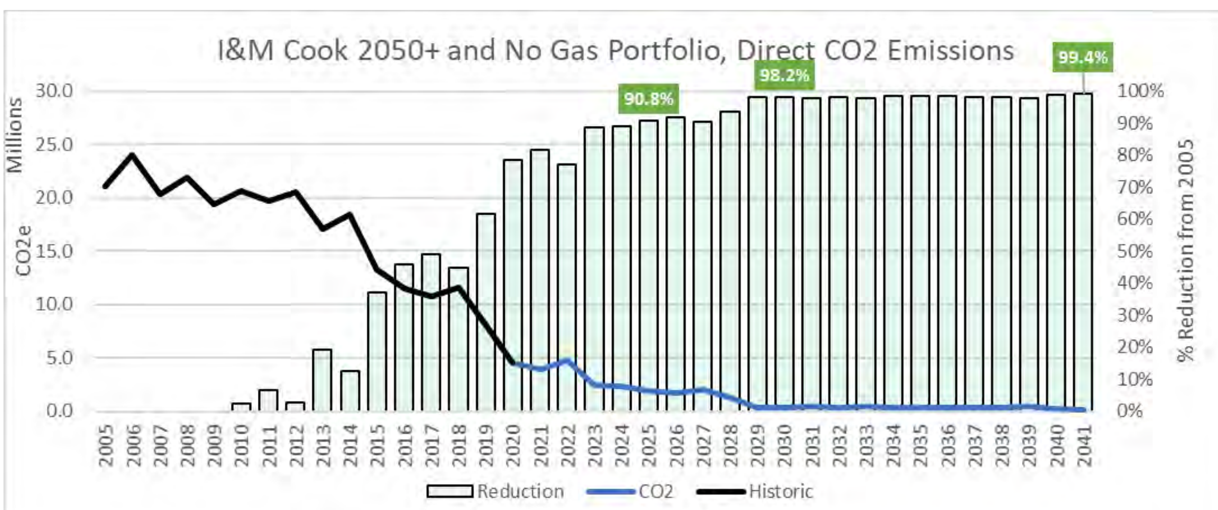


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	136	170	204	234	260	278	293	286	280	258	230	208	190	174	155	145	121
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	650	650	700	750	750	800	800	800	800	800	800	800	800	800
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	50	96	1,916	3,730	3,764	4,444	4,470	4,538	4,603	4,596	4,640	4,618	4,590	4,568	4,550	4,534	4,515	4,505	4,481

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,377	189,516	48	61,149	81,074	124,401	438,417
2022	131,225	222,721	58	53,883	81,705	177,920	504,102
2023	112,176	249,618	34	59,717	48,971	126,614	499,185
2024	114,086	260,833	45	59,601	47,638	126,892	513,814
2025	112,896	574,851	53	14,849	131,685	102,241	673,196
2026	117,485	888,186	54	(27,306)	256,681	84,861	806,589
2027	128,812	881,618	50	(28,081)	268,105	93,038	807,329
2028	119,710	912,271	16,051	(31,174)	293,434	92,266	809,911
2029	107,066	887,794	0	(27,762)	261,112	72,802	778,789
2030	108,751	890,837	0	(28,956)	251,455	64,591	783,768
2031	104,876	869,241	0	(31,775)	227,333	66,128	781,138
2032	110,475	847,759	0	(27,148)	240,092	62,577	753,571
2033	110,399	836,185	0	(28,822)	222,791	50,465	745,437
2034	102,776	811,503	0	(28,867)	279,817	42,062	647,657
2035	107,179	803,195	0	76,294	289,364	8,089	704,302
2036	103,440	789,572	0	74,022	265,835	11,856	713,055
2037	107,302	777,219	0	76,556	281,940	9,059	687,200
2038	107,338	769,327	0	76,612	284,627	8,357	676,338
2039	106,713	748,966	0	76,172	286,212	9,143	654,234
2040	107,118	736,723	0	76,650	276,704	7,778	650,826
2041	106,314	708,422	0	74,964	268,849	9,811	626,247
						NPV $B	**$ 7.03**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,443	444,839	437,016	428,700	421,053
2022	547,083	514,983	498,365	486,963	476,898
2023	559,696	513,455	494,119	478,521	458,261
2024	587,257	535,550	504,629	486,937	465,924
2025	758,920	701,750	665,553	636,864	598,457
2026	920,568	857,798	808,459	761,872	699,760
2027	930,877	857,569	803,898	752,167	681,515
2028	963,750	864,687	806,840	746,834	662,271
2029	960,138	839,037	769,164	702,004	629,542
2030	963,946	844,216	778,244	711,498	625,058
2031	987,225	836,983	762,857	712,180	634,326
2032	952,510	816,149	736,928	673,882	588,229
2033	939,574	800,329	743,631	670,751	574,636
2034	849,529	721,182	640,972	569,476	473,156
2035	905,018	766,377	693,460	625,615	547,792
2036	903,920	780,689	711,239	628,795	545,546
2037	891,788	761,727	682,083	613,645	503,374
2038	867,536	746,048	670,090	605,514	495,426
2039	847,953	719,415	648,574	581,020	465,332
2040	837,529	721,366	643,867	577,181	484,003
2041	824,376	698,141	624,872	540,905	463,666

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,361,317	7,433,658	6,911,252	6,512,788	6,038,960
NPV (2021-2030)	5,058,836	4,609,336	4,355,711	4,177,481	3,982,498
CAGR(2022-2030)	7.52%	6.58%	5.70%	4.74%	3.24%

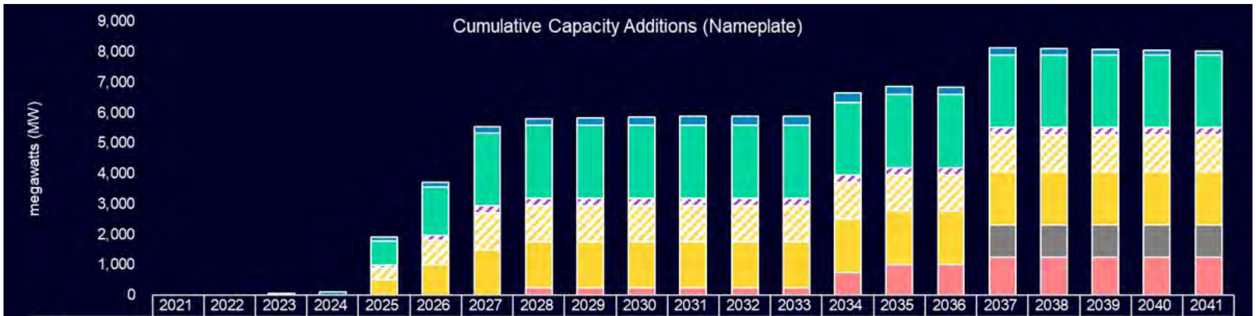


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,284,986	593,283	3,878,269	3,687,128
2022	3,314,691	1,492,385	4,807,076	4,614,933
2023	1,693,924	714,301	2,408,225	2,329,160
2024	1,605,888	717,258	2,323,145	2,247,993
2025	1,650,259	290,285	1,940,544	2,014,804
2026	1,649,566	55,975	1,705,541	1,922,873
2027	1,899,178	93,248	1,992,425	2,198,646
2028	1,206,110	128,043	1,334,152	1,573,475
2029	278,978	110,591	389,570	707,245
2030	238,335	146,652	384,987	699,585
2031	240,384	182,294	422,679	737,156
2032	209,458	143,613	353,071	666,885
2033	213,062	206,032	419,094	727,577
2034	223,080	89,119	312,199	621,577
2035	219,292	103,713	323,006	622,882
2036	226,897	115,379	342,275	643,523
2037	251,394	121,855	373,249	675,066
2038	251,689	119,895	371,585	673,573
2039	333,963	107,900	441,864	748,745
2040	142,903	115,573	258,477	554,530
2041	0	124,526	124,526	410,937

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-7: Portfolio Name: Expanded Build Limits



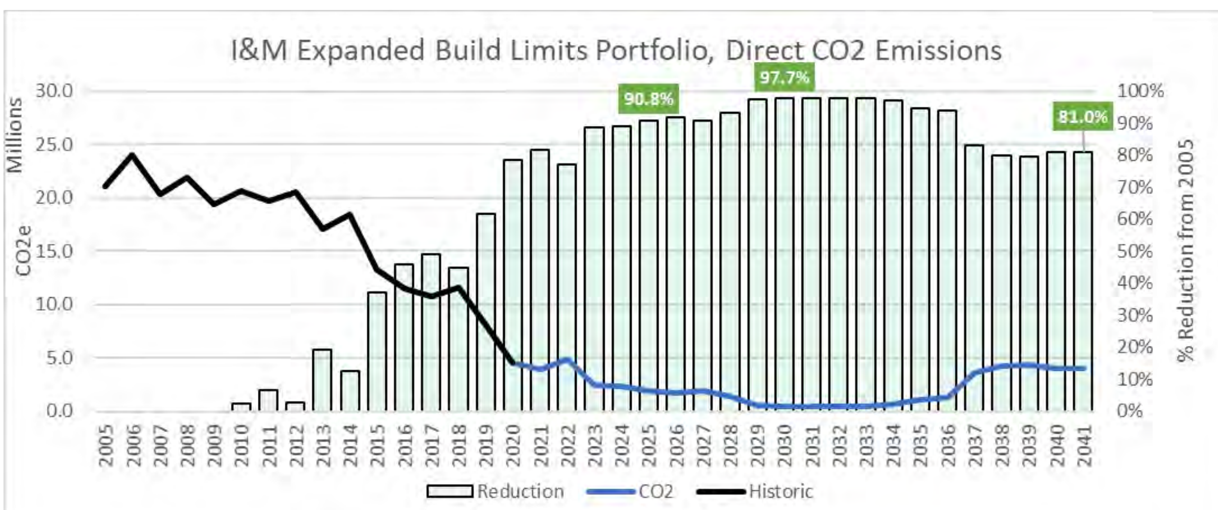
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EE	0	0	50	96	121	157	189	217	246	267	284
Wind	0	0	0	0	800	1,600	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	160	240	240	240	240	240
Hybrid Solar	0	0	0	0	400	800	1,200	1,200	1,200	1,200	1,200
Solar	0	0	0	0	500	1,000	1,500	1,500	1,500	1,500	1,500
Gas CC	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	250	250	250	250
Total	0	0	50	96	1,901	3,717	5,529	5,807	5,836	5,857	5,874

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	294	299	303	269	240	216	195	180	157	131
Wind	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
Storage	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	240	240	240	240	240	240	240	240	240	240
Hybrid Solar	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,200
Solar	1,500	1,500	1,750	1,750	1,750	1,750	1,750	1,750	1,750	1,750
Gas CC	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	250	250	750	1,000	1,000	1,250	1,250	1,250	1,250	1,250
Total	5,884	5,889	6,643	6,859	6,830	8,126	8,105	8,090	8,067	8,041

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	145,157	189,516	50	61,458	81,622	125,055	440,562
2022	131,916	222,721	60	54,154	82,216	178,759	506,507
2023	112,786	241,999	35	60,020	49,310	127,148	493,817
2024	114,651	253,214	45	59,897	47,912	127,497	508,584
2025	113,359	560,714	53	14,919	131,242	102,939	661,950
2026	117,659	880,567	54	(27,298)	255,819	84,894	800,047
2027	128,633	1,180,922	49	(20,311)	381,502	89,531	997,318
2028	128,163	1,092,141	12,536	(23,176)	445,084	85,365	849,819
2029	115,821	1,062,317	2,583	(19,767)	412,937	66,717	814,565
2030	116,375	1,047,192	2,220	(20,991)	396,142	57,924	806,500
2031	111,142	1,016,449	2,116	(23,840)	363,796	57,754	799,593
2032	115,775	997,872	1,797	(19,217)	377,516	56,938	775,497
2033	115,420	978,195	1,576	(20,927)	358,955	41,781	757,036
2034	116,949	1,029,853	4,877	(19,850)	451,626	37,432	717,271
2035	78,926	952,564	6,568	56,145	212,362	30,104	911,683
2036	74,793	934,151	6,703	53,790	193,607	41,779	917,140
2037	216,688	1,067,505	39,733	69,740	409,817	7,001	989,730
2038	162,167	979,231	40,744	39,647	141,958	56,445	1,136,276
2039	163,330	955,459	41,475	39,350	144,538	54,972	1,110,048
2040	158,733	932,641	40,469	39,329	131,795	60,375	1,099,752
2041	158,907	898,368	41,547	39,063	129,444	59,955	1,068,095
						NPV $B	**$ 7.93**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	464,942	445,062	437,273	428,691	421,185
2022	548,197	515,297	498,531	486,993	476,873
2023	552,342	506,886	486,779	470,729	450,646
2024	583,365	528,494	497,386	479,355	458,273
2025	750,103	689,730	652,893	624,117	585,596
2026	913,632	851,194	801,967	755,444	693,785
2027	1,132,980	1,057,333	995,176	935,144	855,371
2028	1,004,623	915,374	856,076	783,270	661,546
2029	1,010,362	885,086	808,868	734,432	624,883
2030	1,002,561	880,218	802,363	724,922	616,420
2031	1,023,560	866,340	788,747	728,131	614,888
2032	992,260	850,364	768,794	695,450	588,112
2033	974,585	827,054	758,402	681,190	546,400
2034	944,218	804,864	710,411	630,153	504,927
2035	1,108,300	967,134	896,990	840,915	770,025
2036	1,104,706	969,532	906,889	844,507	767,055
2037	1,178,854	1,057,287	984,197	910,634	819,491
2038	1,336,115	1,187,713	1,113,151	1,059,964	1,005,915
2039	1,305,338	1,160,732	1,090,688	1,038,336	981,528
2040	1,328,795	1,157,836	1,073,878	1,019,006	950,536
2041	1,261,278	1,122,309	1,049,645	997,075	932,731

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	9,225,882	8,326,459	7,829,533	7,414,614	6,935,971
NPV (2021-2030)	5,239,535	4,772,294	4,505,286	4,330,806	4,102,463
CAGR(2022-2030)	8.06%	7.14%	5.99%	4.97%	3.10%

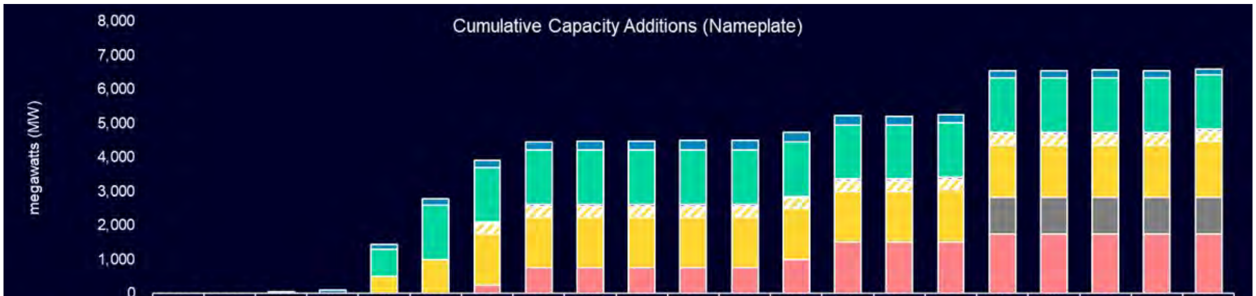


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	Direct I&M	Imports (CO_2e)	Total Direct	Total Lifecycle GHG CO_2e[1]
2021	3,304,306	596,532	3,900,838	3,708,394
2022	3,333,238	1,499,226	4,832,464	4,639,127
2023	1,703,577	716,529	2,420,107	2,340,284
2024	1,613,637	720,243	2,333,881	2,258,260
2025	1,652,725	295,011	1,947,736	2,022,678
2026	1,658,366	56,465	1,714,831	1,931,414
2027	1,883,814	39,281	1,923,095	2,270,949
2028	1,395,760	45,117	1,440,878	1,852,595
2029	491,939	56,148	548,086	1,037,068
2030	425,525	59,971	485,496	967,723
2031	403,485	73,754	477,240	955,924
2032	350,141	92,152	442,294	917,541
2033	341,792	92,395	434,187	902,022
2034	602,978	34,727	637,705	1,170,933
2035	750,901	343,000	1,093,901	1,638,222
2036	745,847	502,383	1,248,231	1,792,606
2037	3,482,797	81,300	3,564,097	4,997,868
2038	3,525,291	681,269	4,206,560	5,650,524
2039	3,640,829	656,792	4,297,621	5,746,163
2040	3,313,559	735,101	4,048,660	5,461,494
2041	3,221,981	784,873	4,006,855	5,408,561

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-8: Portfolio Name: Reference'



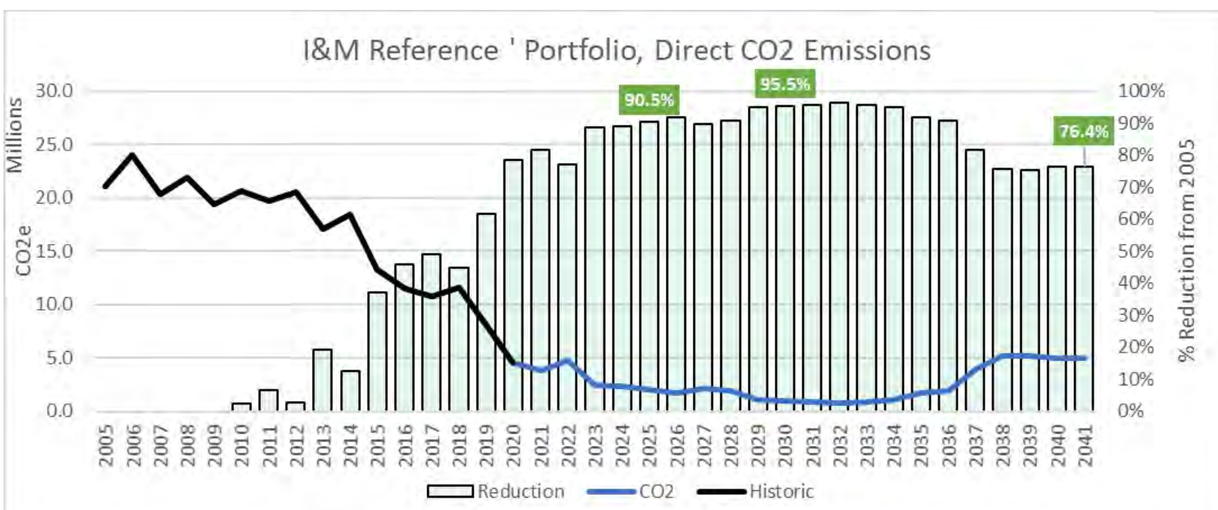
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
EE	0	0	50	96	136	170	204	234	260	278	293
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	0	0	60	60	60	60	60
Hybrid Solar	0	0	0	0	0	0	300	300	300	300	300
Solar	0	0	0	0	500	1,000	1,500	1,500	1,500	1,500	1,500
Gas CC	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750
Total	0	0	50	96	1,436	2,770	3,914	4,444	4,470	4,488	4,503

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	288	283	263	239	234	229	231	234	220	180
Wind	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	60	60	60	60	60	60	60	60	60	60
Hybrid Solar	300	300	300	300	300	300	300	300	300	300
Solar	1,500	1,500	1,500	1,500	1,550	1,550	1,550	1,550	1,550	1,650
Gas CC	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	750	1,000	1,500	1,500	1,500	1,750	1,750	1,750	1,750	1,750
Total	4,498	4,743	5,223	5,199	5,244	6,559	6,561	6,564	6,550	6,610

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,217	189,516	48	61,142	80,898	124,438	438,465
2022	131,251	222,721	59	53,884	81,818	178,007	504,104
2023	112,324	241,999	35	59,725	49,129	126,574	491,525
2024	114,117	253,214	45	59,602	47,737	126,949	506,185
2025	113,013	475,463	53	13,468	114,701	105,911	593,197
2026	117,600	703,445	53	(30,068)	216,545	85,713	660,187
2027	135,875	866,665	49	(27,886)	276,082	92,337	790,958
2028	146,690	808,051	17,449	(30,507)	332,625	90,272	699,241
2029	133,988	784,850	7,887	(27,072)	300,427	70,526	669,277
2030	132,112	775,971	6,797	(28,353)	285,054	62,221	663,455
2031	124,034	750,023	6,466	(31,252)	255,054	64,088	657,594
2032	126,623	730,554	5,442	(26,699)	264,271	61,288	632,503
2033	130,592	738,097	6,334	(28,280)	251,534	47,910	642,898
2034	131,259	756,915	9,800	(28,074)	324,164	41,297	586,298
2035	89,874	680,612	9,950	47,804	102,222	59,217	784,936
2036	85,584	680,846	10,099	45,579	93,416	76,182	804,319
2037	227,748	819,424	42,981	61,642	283,273	11,048	878,189
2038	174,895	741,921	44,427	31,646	62,537	106,041	1,036,705
2039	177,042	724,226	45,486	31,409	66,036	102,294	1,014,422
2040	171,066	700,263	44,001	31,292	57,087	112,321	1,001,857
2041	172,542	674,146	45,665	31,477	62,443	109,829	972,463
						NPV $B	**$ 6.98**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,504	445,048	437,058	428,772	421,123
2022	547,232	514,957	498,383	486,966	476,982
2023	552,091	505,899	486,394	470,986	450,644
2024	579,673	527,959	497,173	479,001	458,305
2025	680,017	623,538	586,975	557,916	520,865
2026	760,564	704,919	662,205	617,658	562,299
2027	915,212	842,152	788,216	736,551	666,324
2028	852,738	753,643	694,685	635,921	537,382
2029	847,692	727,401	660,566	592,750	515,216
2030	845,316	725,751	656,567	593,056	506,447
2031	866,125	713,247	642,424	590,447	507,917
2032	828,955	696,624	615,684	553,504	467,979
2033	839,910	699,829	634,713	571,083	467,300
2034	792,659	661,745	579,175	512,502	404,458
2035	974,079	838,235	762,688	710,761	662,476
2036	991,675	859,180	786,616	735,050	673,183
2037	1,083,482	926,805	869,006	802,752	735,643
2038	1,256,703	1,102,151	1,003,478	960,298	892,332
2039	1,231,616	1,065,714	988,084	941,133	875,301
2040	1,258,475	1,056,998	974,242	914,235	839,610
2041	1,173,698	1,035,920	947,167	900,934	827,055

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,257,589	7,311,618	6,845,909	6,472,383	6,080,146
NPV (2021-2030)	4,691,280	4,242,809	4,000,792	3,814,867	3,623,101
CAGR(2022-2030)	6%	4%	4%	2%	1%

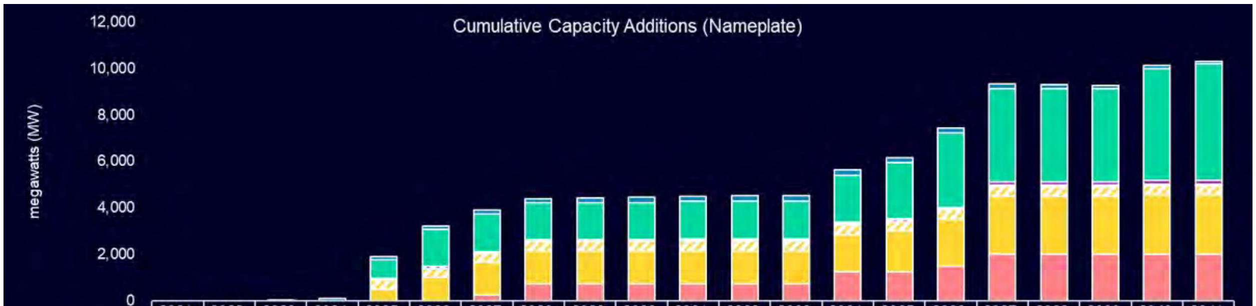


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e**[1]
2021	3,277,210	593,731	3,870,941	3,680,440
2022	3,315,742	1,493,656	4,809,398	4,617,072
2023	1,701,152	713,695	2,414,847	2,335,137
2024	1,607,371	718,128	2,325,499	2,250,206
2025	1,657,547	349,723	2,007,270	2,034,052
2026	1,657,861	68,954	1,726,816	1,849,681
2027	2,087,829	81,476	2,169,306	2,403,476
2028	1,850,665	107,188	1,957,853	2,288,706
2029	946,624	86,068	1,032,692	1,443,518
2030	822,195	119,155	941,350	1,337,400
2031	747,385	157,471	904,856	1,290,030
2032	645,006	128,024	773,030	1,147,592
2033	738,387	175,384	913,770	1,295,525
2034	991,314	81,945	1,073,259	1,489,827
2035	1,033,066	711,555	1,744,620	2,157,450
2036	1,021,132	949,417	1,970,549	2,387,936
2037	3,748,907	133,309	3,882,215	5,193,508
2038	3,822,248	1,325,143	5,147,391	6,477,344
2039	3,961,586	1,277,613	5,239,199	6,577,455
2040	3,590,717	1,405,391	4,996,107	6,292,196
2041	3,541,305	1,443,347	4,984,652	6,288,643

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-9: Portfolio Name: Rapid Technology Advancement



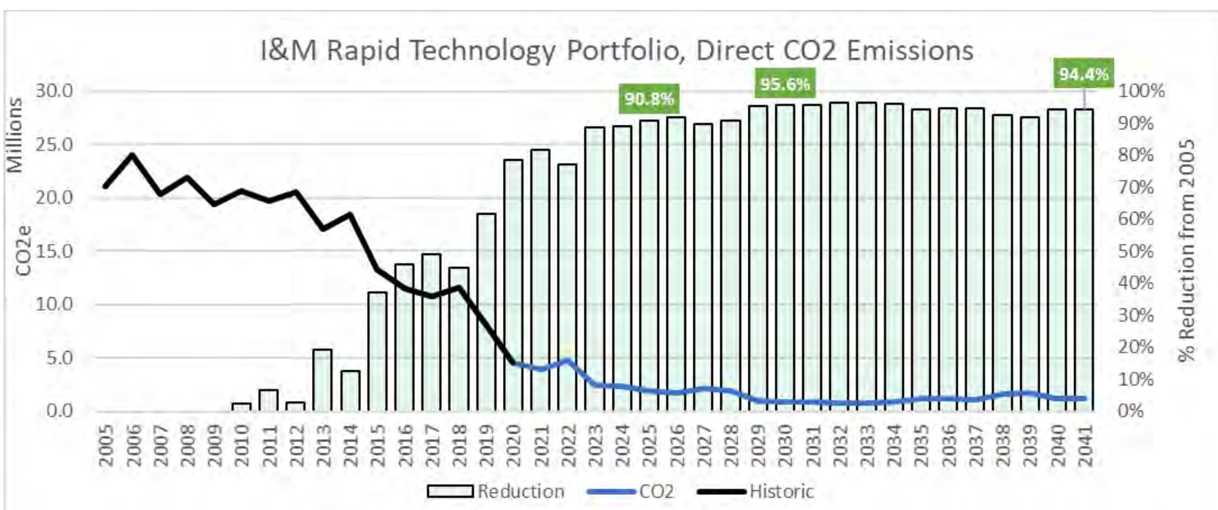
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	51	99	115	147	177	179	203	220	234	241	250	245	225	206	185	164	144	136	113
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	2,000	2,400	3,200	4,000	4,000	4,000	4,800	5,000
Storage	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50	50	150	150	150	150	150
Hybrid Storage	0	0	0	0	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
Hybrid Solar	0	0	0	0	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
Solar	0	0	0	0	500	1,000	1,400	1,400	1,400	1,400	1,400	1,400	1,400	1,600	1,750	2,000	2,500	2,500	2,500	2,550	2,550
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750	750	750	1,250	1,250	1,500	2,000	2,000	2,000	2,000	2,000
Total	0	0	51	99	1,895	3,227	3,907	4,409	4,433	4,450	4,514	4,521	4,530	5,625	6,155	7,436	9,315	9,294	9,274	10,116	10,293

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,337	189,516	48	61,147	81,017	124,417	438,449
2022	131,385	222,721	59	53,890	81,781	177,793	504,067
2023	112,314	242,382	35	59,725	49,175	126,516	491,794
2024	114,089	252,264	45	59,602	47,834	126,797	504,957
2025	112,964	555,415	53	14,852	130,156	102,499	655,617
2026	117,677	877,031	54	(27,299)	254,684	84,892	797,660
2027	135,738	896,193	50	(27,891)	273,188	92,235	823,137
2028	145,876	828,723	17,285	(30,534)	325,291	90,552	726,438
2029	133,150	810,433	7,652	(27,096)	293,292	70,719	701,107
2030	131,453	801,247	6,616	(28,372)	278,326	62,402	694,788
2031	123,469	774,006	6,280	(31,270)	248,884	64,369	687,279
2032	126,172	760,254	5,325	(26,715)	258,892	61,389	667,081
2033	125,221	746,044	4,674	(28,431)	240,113	48,224	655,431
2034	125,260	914,180	7,792	(22,571)	409,750	37,289	651,576
2035	82,899	862,817	7,940	54,161	181,232	28,981	855,169
2036	80,630	1,024,323	8,835	58,326	262,217	22,518	931,595
2037	90,550	1,227,621	10,590	68,122	397,984	9,505	1,007,193
2038	33,137	1,261,493	10,500	43,527	217,034	44,903	1,174,120
2039	36,047	1,229,714	11,386	43,379	222,550	44,072	1,141,336
2040	30,546	1,328,743	9,389	49,355	288,392	27,570	1,156,811
2041	36,297	1,313,095	11,926	50,722	309,852	23,114	1,122,440
						NPV $B	$ 7.50

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,439	444,955	437,290	428,695	421,077
2022	547,128	514,916	498,320	486,847	476,855
2023	552,165	506,113	486,700	471,204	450,889
2024	578,453	526,375	495,989	477,957	457,259
2025	741,205	684,818	648,072	619,911	580,952
2026	910,690	848,592	799,705	753,041	689,544
2027	945,900	873,789	820,577	769,597	698,420
2028	879,811	780,243	722,002	664,267	565,232
2029	878,827	758,847	691,238	625,383	549,967
2030	875,767	755,847	687,754	624,677	540,520
2031	895,443	742,265	672,384	618,937	538,724
2032	862,073	730,225	650,274	589,449	503,144
2033	849,930	710,844	650,300	584,202	484,945
2034	870,493	735,809	648,545	570,534	455,290
2035	1,049,468	910,035	838,824	786,732	715,535
2036	1,121,974	989,731	924,061	849,188	770,532
2037	1,202,556	1,087,823	1,005,978	928,573	790,700
2038	1,354,880	1,233,412	1,158,242	1,105,225	1,024,830
2039	1,320,520	1,190,292	1,133,314	1,070,408	982,309
2040	1,339,857	1,220,021	1,150,483	1,089,641	997,019
2041	1,318,256	1,190,716	1,112,828	1,042,023	966,284

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,808,653	7,866,137	7,375,296	6,970,337	6,540,953
NPV (2021-2030)	4,895,200	4,441,228	4,203,464	4,022,062	3,827,547
CAGR(2022-2030)	6.16%	5.03%	4.13%	3.04%	1.32%

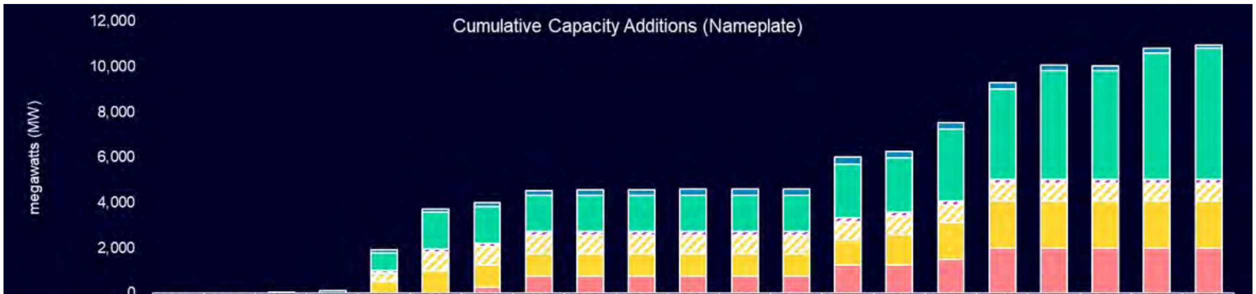


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,282,883	593,567	3,876,450	3,685,530
2022	3,322,290	1,490,656	4,812,946	4,620,102
2023	1,700,516	712,630	2,413,146	2,333,480
2024	1,604,406	716,753	2,321,159	2,245,912
2025	1,651,229	295,382	1,946,611	2,020,429
2026	1,655,844	57,084	1,712,928	1,929,219
2027	2,079,709	81,725	2,161,435	2,394,417
2028	1,823,861	111,793	1,935,654	2,264,658
2029	921,981	89,221	1,011,202	1,418,964
2030	802,497	122,719	925,215	1,318,842
2031	728,158	162,684	890,843	1,273,696
2032	629,066	128,763	757,829	1,130,499
2033	594,224	179,696	773,920	1,135,911
2034	823,286	35,294	858,580	1,304,501
2035	848,607	331,162	1,179,769	1,649,156
2036	887,419	259,470	1,146,889	1,694,893
2037	1,037,683	95,064	1,132,746	1,794,368
2038	1,038,555	530,268	1,568,822	2,272,540
2039	1,211,137	509,794	1,720,931	2,442,283
2040	861,795	321,108	1,182,904	1,915,627
2041	883,272	297,761	1,181,034	1,936,381

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-10: Portfolio Name: Enhanced Regulation

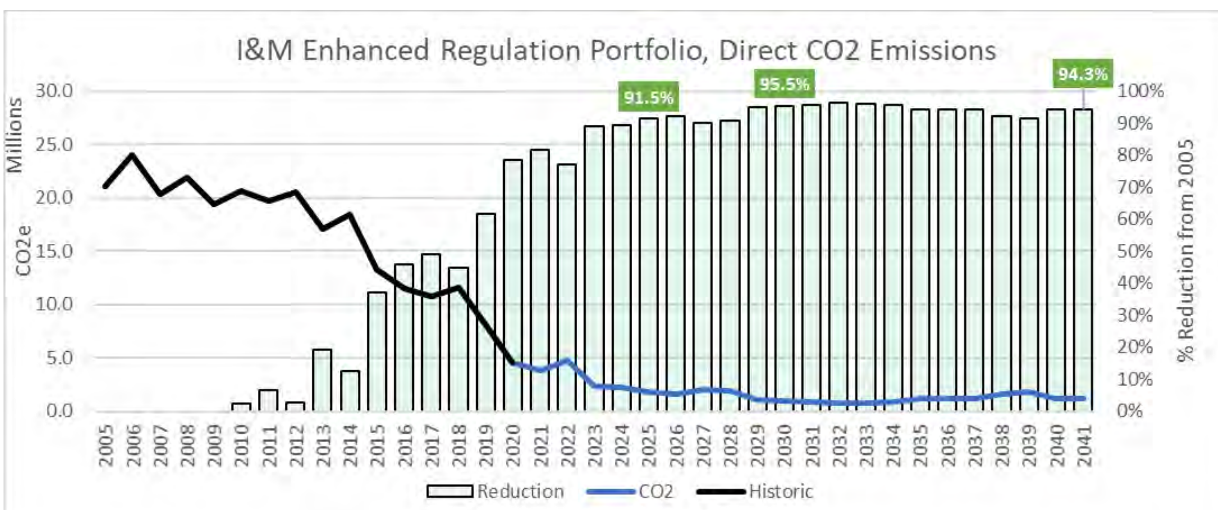


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	131	171	201	223	250	268	277	280	282	287	282	278	272	251	228	199	156
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	2,400	2,400	3,200	4,000	4,800	4,800	5,600	5,800
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,100	1,350	1,600	2,050	2,050	2,050	2,050	2,050
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750	750	750	1,250	1,250	1,500	2,000	2,000	2,000	2,000	2,000
Total	0	0	50	96	1,911	3,731	4,011	4,533	4,560	4,578	4,587	4,590	4,592	5,997	6,242	7,538	9,282	10,061	10,038	10,809	10,966

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	**Fixed Cost**	**Emissions Cost**	**Variable O&M**	**Energy Export Revenue**	**Energy Import Cost**	**Cost to Serve Load**
2021	144,291	189,516	48	61,145	80,928	124,343	438,416
2022	131,329	222,721	58	53,866	82,542	179,140	504,571
2023	111,074	241,999	33	59,621	47,116	127,288	492,893
2024	113,111	253,214	43	59,502	46,191	127,894	507,797
2025	110,980	519,366	51	14,711	128,156	102,641	619,582
2026	116,440	815,798	54	(27,404)	255,405	85,032	734,501
2027	135,241	854,554	46	(27,974)	274,479	92,426	779,814
2028	146,567	828,957	16,853	(30,560)	330,927	90,474	721,280
2029	134,280	806,561	7,949	(27,067)	300,447	70,562	691,361
2030	132,252	797,338	6,860	(28,351)	284,398	62,220	685,646
2031	124,166	822,314	6,496	(31,250)	253,889	64,168	731,291
2032	126,739	807,289	5,467	(26,697)	263,569	61,314	710,106
2033	125,849	792,008	4,805	(28,409)	244,173	48,135	698,072
2034	126,210	961,610	8,054	(22,537)	415,284	37,352	694,802
2035	83,934	892,618	8,199	54,191	184,946	29,039	882,521
2036	82,636	1,002,811	9,400	58,382	269,717	22,449	905,145
2037	94,145	1,247,835	11,384	68,234	414,276	9,614	1,015,904
2038	35,775	1,270,378	11,260	43,609	228,710	44,439	1,175,118
2039	39,293	1,268,027	12,342	43,460	234,530	43,806	1,171,623
2040	31,603	1,368,439	9,713	49,385	297,153	27,431	1,189,005
2041	37,292	1,319,620	12,243	50,746	317,759	23,044	1,122,018
						NPV $B	**$ 7.49**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,471	444,911	437,233	428,728	420,886
2022	548,292	514,906	498,855	487,402	477,260
2023	551,861	506,850	487,441	472,149	451,785
2024	581,741	528,859	498,736	481,473	459,951
2025	706,051	648,555	611,923	583,708	544,168
2026	847,835	784,752	735,962	689,606	626,507
2027	905,527	830,806	775,917	725,164	656,045
2028	872,830	775,423	716,917	658,927	558,049
2029	870,084	749,636	682,914	616,023	536,063
2030	867,872	747,945	679,405	615,613	528,277
2031	940,581	786,689	715,982	663,462	581,112
2032	907,116	773,893	693,206	631,122	545,822
2033	894,501	754,006	693,489	625,001	526,063
2034	915,070	778,461	690,965	612,215	496,605
2035	1,078,484	938,787	866,002	812,834	743,609
2036	1,098,357	964,145	897,549	822,335	743,509
2037	1,215,619	1,099,951	1,013,524	933,999	793,981
2038	1,361,078	1,234,545	1,161,472	1,104,542	1,021,823
2039	1,356,171	1,224,164	1,159,899	1,097,565	1,009,008
2040	1,376,279	1,253,919	1,181,915	1,120,474	1,022,767
2041	1,320,529	1,191,582	1,112,610	1,039,478	962,055

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,806,379	7,865,043	7,366,958	6,961,794	6,512,057
NPV (2021-2030)	4,789,479	4,337,179	4,101,709	3,914,749	3,717,375
CAGR(2022-2030)	6.02%	4.88%	3.96%	2.82%	1.05%

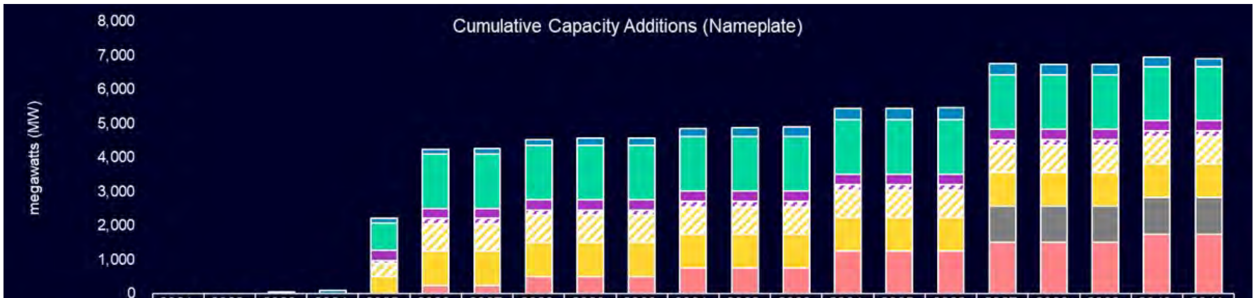


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e**[1]
2021	3,280,303	592,536	3,872,840	3,682,067
2022	3,297,643	1,510,029	4,807,672	4,616,718
2023	1,593,388	724,130	2,317,519	2,247,400
2024	1,506,868	731,860	2,238,727	2,172,420
2025	1,509,051	296,112	1,805,164	1,892,028
2026	1,557,081	56,637	1,613,718	1,840,258
2027	2,003,211	81,170	2,084,382	2,327,977
2028	1,799,562	108,769	1,908,331	2,246,230
2029	953,622	86,104	1,039,726	1,451,397
2030	825,597	118,979	944,577	1,341,015
2031	750,522	158,496	909,018	1,294,570
2032	647,980	129,059	777,038	1,151,940
2033	614,781	178,135	792,916	1,157,339
2034	852,956	35,323	888,278	1,337,889
2035	878,455	330,245	1,208,700	1,681,791
2036	943,324	255,757	1,199,081	1,754,171
2037	1,135,211	94,310	1,229,522	1,903,661
2038	1,128,048	519,650	1,647,698	2,362,844
2039	1,302,652	501,303	1,803,955	2,536,789
2040	890,909	318,718	1,209,627	1,946,114
2041	902,005	297,063	1,199,068	1,957,049

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-11: Portfolio Name: Rockport 1 -2024 NTG

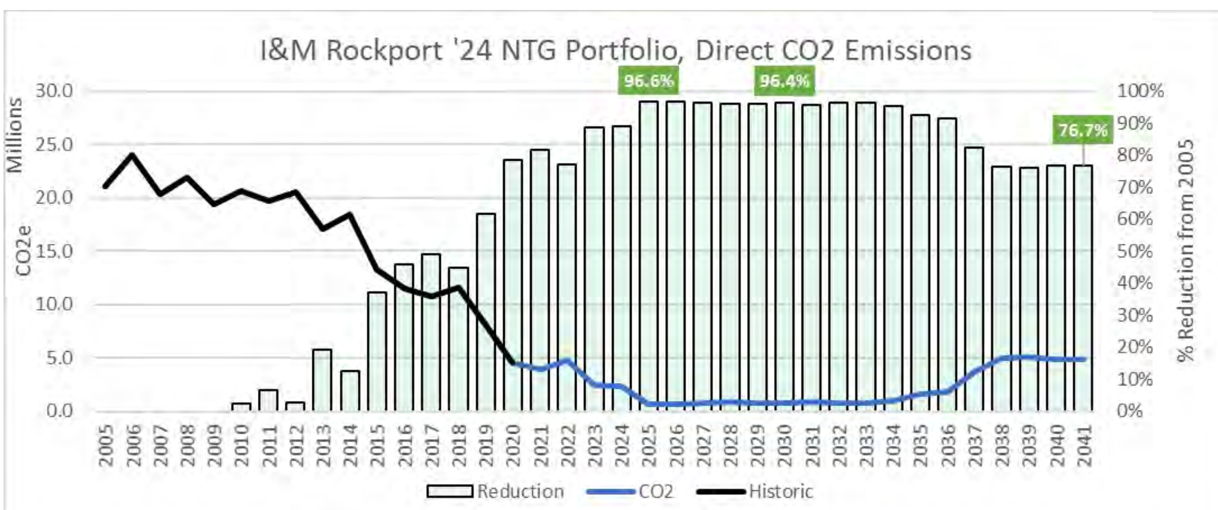


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	46	88	129	138	157	174	220	221	246	272	303	330	339	352	344	318	299	282	231
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Hybrid Storage	0	0	0	0	80	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160	160
Hybrid Solar	0	0	0	0	400	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800	800
Solar	0	0	0	0	500	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	250	250	500	500	500	750	750	750	1,250	1,250	1,250	1,500	1,500	1,500	1,750	1,750
Total	0	0	46	88	2,209	4,248	4,267	4,534	4,580	4,581	4,856	4,882	4,913	5,440	5,449	5,462	6,774	6,748	6,729	6,962	6,911

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,331	189,516	48	61,146	80,946	124,348	438,444
2022	131,313	222,721	59	53,889	81,778	177,865	504,068
2023	112,237	232,249	34	59,719	48,560	127,002	482,678
2024	113,202	239,963	44	59,569	47,046	129,600	495,325
2025	87,317	591,899	0	13,598	93,776	104,594	703,632
2026	100,991	921,551	7	(28,275)	224,456	85,045	854,863
2027	107,056	916,921	4	(29,294)	228,195	93,372	859,864
2028	118,977	834,889	5,068	(31,640)	276,582	92,772	743,231
2029	125,048	826,825	5,268	(27,304)	281,756	71,187	718,952
2030	124,330	810,497	4,535	(28,556)	268,017	62,975	705,605
2031	123,868	810,720	6,412	(31,259)	250,738	64,472	722,770
2032	126,473	795,865	5,395	(26,706)	262,942	61,427	699,080
2033	125,543	780,601	4,774	(28,409)	245,025	48,065	685,358
2034	126,455	805,612	8,152	(28,209)	323,038	40,934	629,295
2035	84,607	727,291	8,369	47,662	101,534	56,021	822,081
2036	80,351	709,472	8,359	45,267	91,915	72,968	824,085
2037	222,650	843,199	41,457	61,313	286,400	10,335	891,313
2038	169,877	761,437	42,887	31,319	59,999	100,261	1,046,080
2039	171,616	743,254	43,811	31,080	62,443	96,942	1,024,260
2040	170,289	747,073	43,801	31,069	60,987	105,602	1,036,848
2041	172,017	714,941	45,533	30,923	63,219	104,712	1,005,855
						NPV $B	$ 7.43

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,475	445,072	436,971	428,706	421,164
2022	547,236	514,841	498,306	486,996	476,969
2023	543,283	497,150	477,419	462,087	441,708
2024	570,406	517,396	485,828	467,537	448,502
2025	795,006	732,030	696,869	669,311	637,958
2026	959,307	895,253	854,395	811,510	762,020
2027	980,113	905,792	851,982	811,954	748,162
2028	901,638	794,407	735,766	681,419	594,811
2029	897,633	778,410	710,180	641,601	566,236
2030	887,330	765,992	698,498	636,674	549,660
2031	931,945	778,087	707,254	654,917	574,123
2032	895,834	762,684	682,967	620,495	534,835
2033	881,774	741,606	681,186	612,468	513,453
2034	834,139	705,674	624,218	553,108	451,343
2035	1,010,862	873,618	800,691	753,381	696,428
2036	1,010,831	879,104	807,766	755,566	691,982
2037	1,096,525	939,278	882,635	814,767	747,482
2038	1,265,366	1,109,190	1,014,892	968,781	903,770
2039	1,239,990	1,073,324	1,000,560	950,684	884,960
2040	1,295,061	1,094,447	1,008,163	951,145	877,837
2041	1,205,115	1,068,430	980,517	934,580	861,110

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,703,931	7,769,030	7,283,464	6,911,258	6,522,256
NPV (2021-2030)	4,999,431	4,561,581	4,311,849	4,123,502	3,934,935
CAGR(2022-2030)	6.32%	5.22%	4.31%	3.27%	1.52%

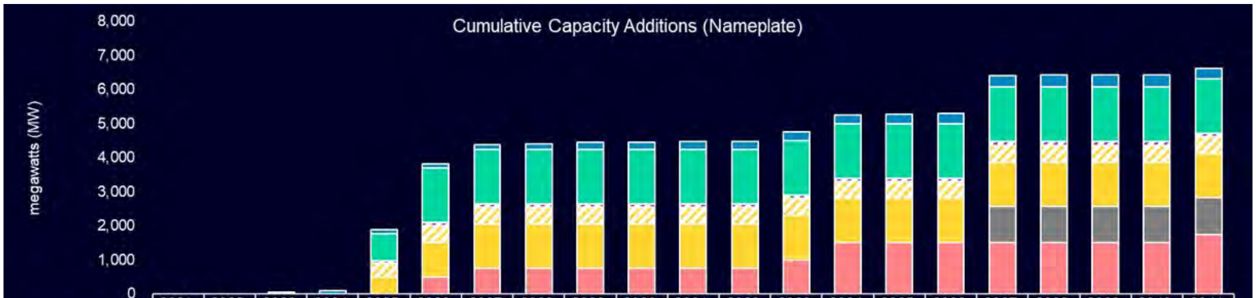


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,282,847	592,629	3,875,476	3,684,533
2022	3,318,821	1,491,647	4,810,468	4,617,889
2023	1,696,953	720,093	2,417,046	2,337,705
2024	1,566,335	753,884	2,320,219	2,248,570
2025	386,089	322,856	708,945	895,916
2026	657,838	55,796	713,634	1,077,480
2027	662,099	95,347	757,446	1,118,350
2028	711,866	131,167	843,033	1,226,373
2029	724,306	93,518	817,824	1,197,681
2030	627,117	127,987	755,104	1,123,998
2031	742,143	163,612	905,755	1,290,279
2032	640,377	127,955	768,332	1,142,314
2033	606,105	177,998	784,102	1,147,470
2034	861,133	77,620	938,753	1,337,230
2035	897,108	673,067	1,570,175	1,964,101
2036	888,415	910,509	1,798,924	2,191,941
2037	3,624,450	123,866	3,748,316	5,035,173
2038	3,698,259	1,256,178	4,954,437	6,260,158
2039	3,827,870	1,213,089	5,040,959	6,353,535
2040	3,574,630	1,323,894	4,898,523	6,185,019
2041	3,531,076	1,383,615	4,914,691	6,198,506

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-12: Portfolio Name: Rockport 1 -2026 NTG



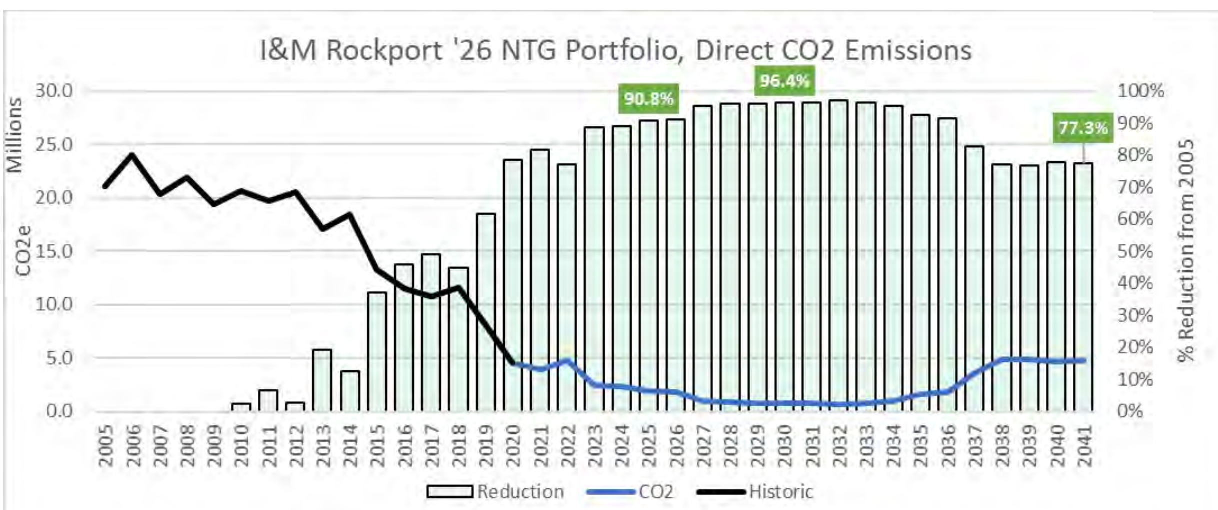
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	46	88	110	125	145	165	215	215	222	236	251	266	280	307	341	352	367	371	306
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	80	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Hybrid Solar	0	0	0	0	400	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
Solar	0	0	0	0	500	1,000	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,300
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	500	750	750	750	750	750	750	1,000	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,750
Total	0	0	46	88	1,890	3,825	4,395	4,415	4,465	4,465	4,472	4,486	4,751	5,266	5,280	5,307	6,411	6,422	6,437	6,441	6,626

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,398	189,516	48	61,150	81,105	124,421	438,430
2022	131,306	222,721	58	53,887	81,773	177,889	504,088
2023	112,269	239,845	34	59,720	48,641	127,038	490,263
2024	114,053	251,176	45	59,600	46,911	127,735	505,691
2025	112,892	555,648	53	14,849	129,429	102,862	656,865
2026	132,407	863,748	53	(27,935)	253,113	84,971	800,130
2027	121,054	921,676	13	(28,901)	243,386	92,737	863,192
2028	127,951	817,725	7,561	(31,417)	289,254	92,560	724,748
2029	133,921	810,533	7,869	(27,077)	294,471	70,895	701,197
2030	132,003	794,211	6,767	(28,358)	278,800	62,647	688,233
2031	123,984	767,046	6,450	(31,256)	249,226	64,673	680,962
2032	126,582	753,415	5,431	(26,702)	260,475	61,622	659,438
2033	130,569	760,670	6,291	(28,274)	248,826	48,187	668,428
2034	131,118	787,155	9,756	(28,080)	325,857	41,196	614,557
2035	89,703	716,448	9,947	47,797	106,133	57,458	814,872
2036	85,384	703,286	10,037	45,399	96,691	73,836	820,699
2037	222,945	824,443	41,533	61,329	284,781	10,430	874,647
2038	170,119	744,022	42,949	31,331	60,007	100,733	1,029,447
2039	171,797	726,625	43,863	31,091	62,923	96,732	1,007,185
2040	166,338	704,018	42,581	30,975	55,705	105,233	993,441
2041	172,176	688,463	45,568	30,935	64,196	104,061	978,291
						NPV $B	**$ 7.26**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,474	444,940	437,127	428,702	421,097
2022	546,999	514,912	498,428	486,859	476,816
2023	550,959	504,804	485,060	469,670	449,258
2024	579,285	527,328	496,698	478,965	457,814
2025	742,786	686,087	649,279	620,853	582,260
2026	900,680	846,151	800,805	756,858	703,735
2027	982,445	909,496	854,323	816,240	752,528
2028	879,463	776,083	719,218	663,396	570,012
2029	879,214	760,040	691,142	625,212	547,789
2030	871,037	749,123	680,877	617,812	532,921
2031	890,383	736,243	665,203	613,501	532,711
2032	855,867	723,308	642,721	581,498	495,724
2033	864,756	724,518	660,777	596,749	493,966
2034	820,440	690,522	607,883	539,981	433,048
2035	1,004,618	867,658	793,275	740,584	689,936
2036	1,008,277	876,576	804,146	752,233	689,754
2037	1,079,883	922,481	865,972	798,275	731,236
2038	1,248,859	1,093,016	998,255	951,973	886,774
2039	1,223,405	1,056,410	983,230	933,657	867,677
2040	1,250,852	1,050,724	964,687	907,461	835,146
2041	1,176,878	1,040,738	953,059	907,020	833,586

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,534,928	7,590,090	7,118,829	6,746,380	6,361,432
NPV (2021-2030)	4,910,009	4,471,146	4,224,077	4,039,196	3,853,629
CAGR(2022-2030)	6.07%	4.90%	4.01%	2.91%	1.14%

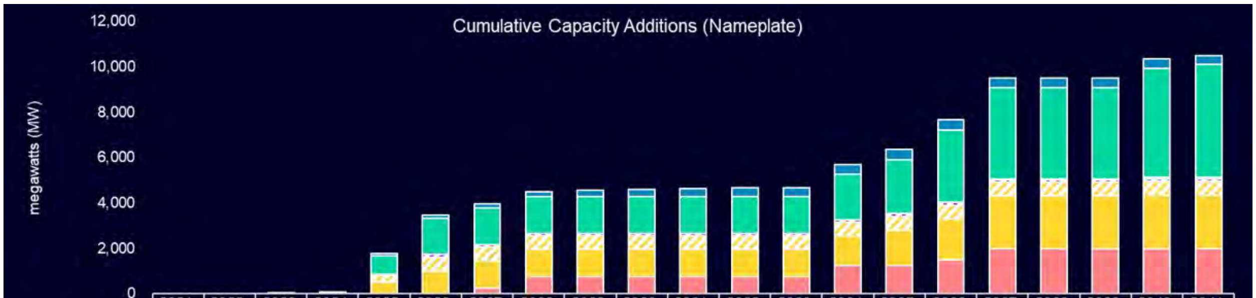


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,286,018	593,600	3,879,618	3,688,340
2022	3,318,504	1,491,945	4,810,449	4,617,979
2023	1,698,625	720,601	2,419,226	2,339,745
2024	1,604,223	730,335	2,334,558	2,259,570
2025	1,650,086	300,116	1,950,203	2,024,496
2026	1,790,972	54,481	1,845,453	2,357,629
2027	855,241	85,290	940,531	1,541,172
2028	714,865	131,139	846,004	1,472,337
2029	727,801	90,227	818,028	1,446,044
2030	630,194	124,898	755,092	1,340,025
2031	581,220	165,559	746,779	1,296,151
2032	502,193	130,440	632,634	1,148,565
2033	610,415	179,120	789,535	1,297,736
2034	865,645	80,310	945,955	1,483,643
2035	903,316	689,711	1,593,027	2,130,079
2036	894,351	920,523	1,814,874	2,347,029
2037	3,521,159	127,225	3,648,384	5,046,339
2038	3,594,671	1,260,104	4,854,776	6,270,447
2039	3,712,188	1,207,927	4,920,115	6,353,627
2040	3,379,095	1,315,946	4,695,041	6,068,856
2041	3,415,260	1,372,693	4,787,952	6,191,119

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-13: Portfolio Name: Rapid Technology Advancement - NTG



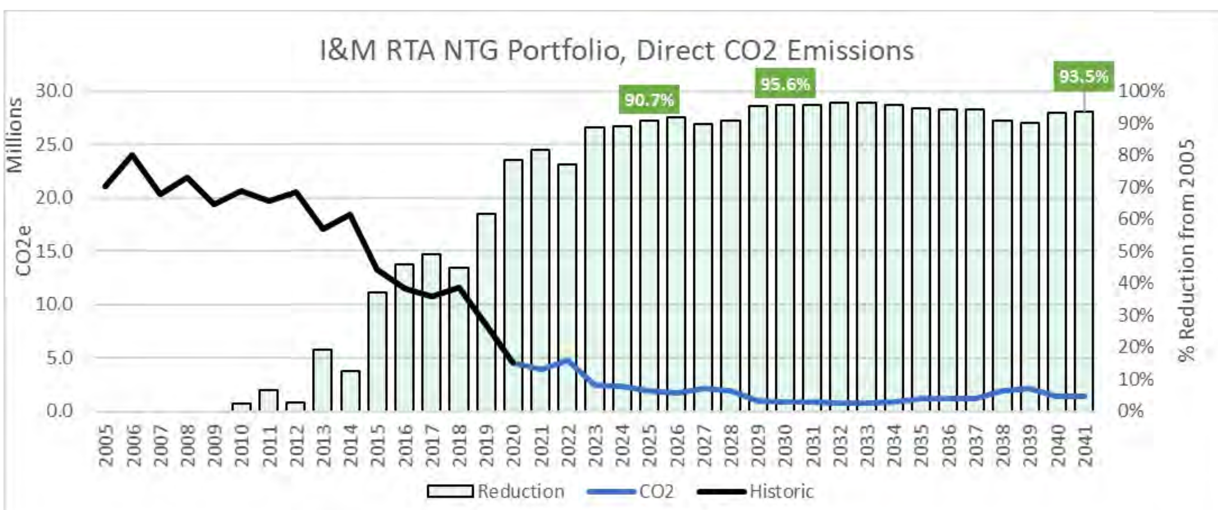
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	46	89	125	163	200	236	281	323	361	385	407	430	446	448	451	448	445	437	386
Wind	0	0	0	0	800	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	2,000	2,400	3,200	4,000	4,000	4,000	4,800	5,000
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50	50	50	50	50
Hybrid Storage	0	0	0	0	60	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120	120
Hybrid Solar	0	0	0	0	300	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Solar	0	0	0	0	500	1,000	1,200	1,200	1,200	1,200	1,200	1,200	1,200	1,300	1,550	1,800	2,300	2,300	2,300	2,350	2,350
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	250	750	750	750	750	750	750	1,250	1,250	1,500	2,000	2,000	2,000	2,000	2,000
Total	0	0	46	89	1,785	3,483	3,970	4,506	4,551	4,593	4,631	4,655	4,677	5,700	6,366	7,668	9,521	9,518	9,515	10,357	10,506

Mean IRP Cost to Serve Load (2019 $,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,363	189,516	48	61,149	81,077	124,397	438,396
2022	131,213	222,721	58	53,883	81,782	178,008	504,101
2023	112,307	237,568	34	59,723	48,776	126,999	487,853
2024	113,939	247,917	45	59,596	46,964	127,625	502,152
2025	113,083	538,321	53	14,510	125,819	103,300	643,439
2026	117,631	830,850	54	(27,993)	244,405	85,048	761,173
2027	135,686	879,225	50	(27,895)	272,866	92,307	806,508
2028	145,806	821,791	17,242	(30,537)	327,937	90,357	716,548
2029	133,161	798,670	7,657	(27,096)	297,270	70,559	685,221
2030	131,438	789,643	6,615	(28,373)	284,587	62,091	676,595
2031	123,446	760,974	6,274	(31,271)	255,850	63,834	666,716
2032	126,134	744,705	5,312	(26,717)	267,358	60,988	642,613
2033	125,204	730,874	4,693	(28,423)	248,632	47,566	631,071
2034	125,489	834,463	7,825	(25,233)	375,792	38,407	604,572
2035	82,851	847,695	7,927	54,159	192,024	27,244	827,456
2036	82,016	1,003,145	9,211	58,360	278,833	21,426	894,420
2037	93,309	1,218,371	11,203	68,371	426,558	9,064	972,712
2038	36,380	1,129,262	11,421	38,174	166,963	66,015	1,112,856
2039	40,024	1,102,093	12,503	38,062	173,675	64,519	1,083,264
2040	32,579	1,210,502	9,962	44,114	234,661	40,738	1,102,808
2041	37,555	1,196,066	12,268	45,505	255,510	35,090	1,068,427
						NPV $B	$ 7.28

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,447	444,822	436,914	428,651	421,250
2022	546,950	514,996	498,370	486,938	476,878
2023	548,441	501,668	482,691	467,056	446,901
2024	576,292	523,722	493,256	474,605	454,491
2025	729,056	672,986	636,094	608,066	567,683
2026	870,653	810,896	763,370	716,795	657,035
2027	929,177	856,972	803,901	753,112	682,192
2028	869,802	770,499	712,220	653,922	556,878
2029	862,937	742,373	675,507	609,125	533,119
2030	857,579	738,931	670,141	606,788	520,577
2031	874,122	721,956	651,735	598,940	517,607
2032	838,505	706,541	626,636	563,659	477,889
2033	827,730	687,887	626,405	558,695	457,244
2034	822,441	682,790	599,020	525,072	421,729
2035	1,022,521	880,379	812,130	759,282	687,528
2036	1,085,763	955,008	888,201	810,815	731,885
2037	1,168,192	1,057,542	970,533	891,466	748,663
2038	1,307,829	1,170,793	1,094,684	1,044,635	970,106
2039	1,258,662	1,129,256	1,069,100	1,010,508	939,028
2040	1,287,549	1,160,096	1,091,481	1,036,139	955,204
2041	1,254,110	1,130,044	1,057,187	987,548	919,107

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,586,066	7,660,665	7,168,633	6,756,284	6,337,117
NPV (2021-2030)	4,822,275	4,370,475	4,131,172	3,949,631	3,755,185
CAGR(2022-2030)	5.90%	4.71%	3.79%	2.64%	0.86%

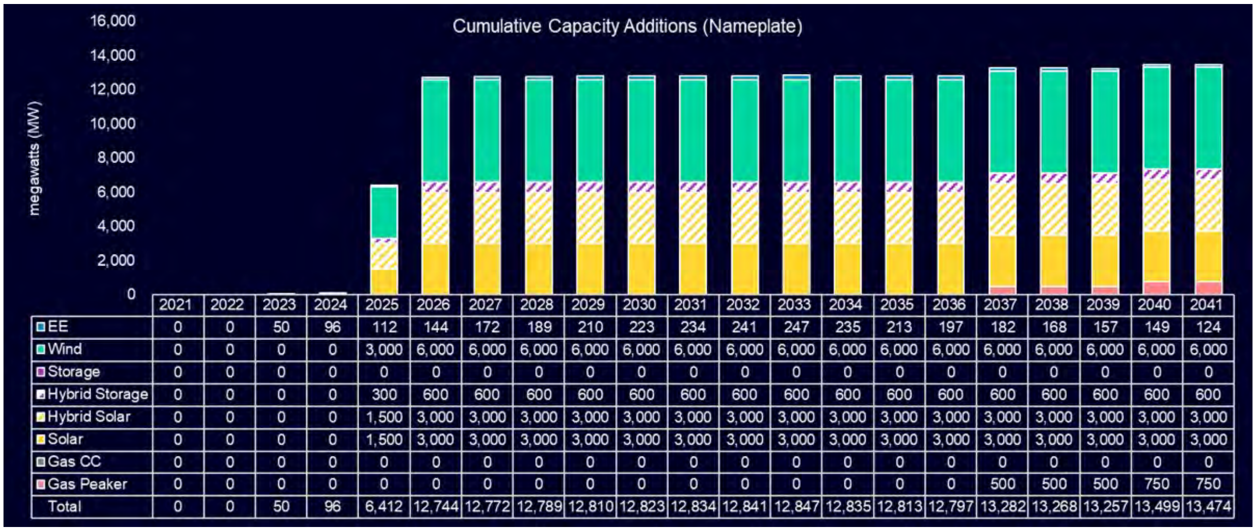


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e[1]**
2021	3,284,393	593,245	3,877,638	3,686,513
2022	3,313,916	1,493,589	4,807,505	4,615,377
2023	1,700,421	720,011	2,420,432	2,340,797
2024	1,597,095	729,785	2,326,880	2,252,311
2025	1,657,375	308,629	1,966,004	2,027,557
2026	1,654,190	59,485	1,713,675	1,906,681
2027	2,077,451	82,756	2,160,207	2,393,458
2028	1,820,183	109,360	1,929,543	2,258,994
2029	922,573	87,587	1,010,159	1,417,993
2030	802,332	118,458	920,791	1,314,396
2031	727,693	155,363	883,055	1,265,845
2032	627,781	122,426	750,207	1,122,717
2033	593,718	171,065	764,784	1,126,713
2034	830,159	48,569	878,728	1,305,300
2035	847,262	309,273	1,156,535	1,625,760
2036	925,221	243,032	1,168,254	1,721,105
2037	1,111,600	87,347	1,198,947	1,876,051
2038	1,138,528	791,513	1,930,041	2,610,347
2039	1,325,028	761,935	2,086,963	2,786,464
2040	909,591	484,227	1,393,819	2,102,261
2041	922,818	449,713	1,372,531	2,102,824

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-14: Portfolio Name: Reference No Renewable Limits

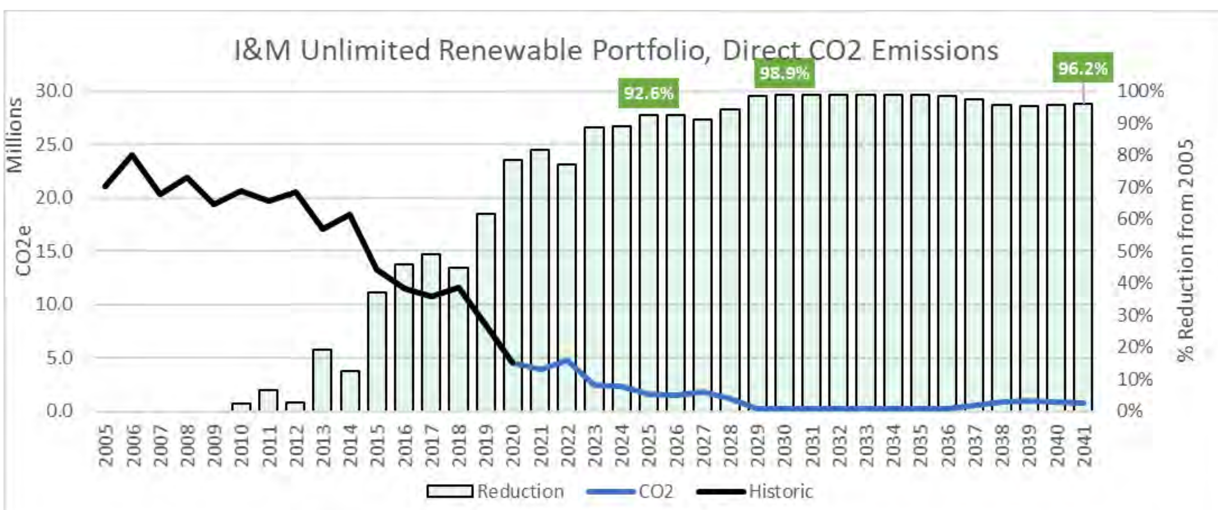


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	112	144	172	189	210	223	234	241	247	235	213	197	182	168	157	149	124
Wind	0	0	0	0	3,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hybrid Storage	0	0	0	0	300	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
Hybrid Solar	0	0	0	0	1,500	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Solar	0	0	0	0	1,500	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaker	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	500	500	500	750	750
Total	0	0	50	96	6,412	12,744	12,772	12,789	12,810	12,823	12,834	12,841	12,847	12,835	12,813	12,797	13,282	13,268	13,257	13,499	13,474

Mean IRP Cost to Serve Load (2019 $,000)							
	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,386	189,516	48	61,150	81,119	124,417	438,399
2022	131,296	222,721	58	53,886	81,804	177,939	504,097
2023	112,227	241,999	35	59,720	49,079	126,644	491,541
2024	114,072	253,214	45	59,600	47,647	126,920	506,198
2025	111,499	1,368,212	53	(105,200)	411,812	85,132	1,047,874
2026	116,151	2,455,628	53	(269,940)	843,551	80,934	1,539,263
2027	128,176	2,412,733	48	(273,213)	871,028	86,946	1,483,658
2028	119,095	2,268,892	15,902	(279,597)	1,042,151	81,749	1,157,927
2029	107,066	2,211,485	0	(268,681)	1,003,793	63,883	1,109,960
2030	108,752	2,169,754	0	(272,453)	965,495	53,573	1,094,130
2031	104,876	2,111,392	0	(277,679)	913,326	52,745	1,078,009
2032	110,474	2,067,892	0	(267,582)	923,191	53,652	1,041,246
2033	110,395	2,025,257	0	(270,808)	907,911	35,132	992,065
2034	102,771	1,974,124	0	(272,997)	974,990	35,173	864,081
2035	58,382	1,871,184	0	87,107	712,487	5,501	1,309,385
2036	54,539	1,834,150	0	84,902	685,849	7,384	1,295,127
2037	68,328	1,841,408	3,136	87,639	717,454	5,811	1,288,407
2038	10,148	1,738,058	3,164	57,460	429,162	35,377	1,414,646
2039	10,847	1,695,076	3,384	57,188	430,380	35,259	1,371,231
2040	14,251	1,679,378	4,340	57,672	424,616	34,355	1,365,194
2041	16,136	1,627,002	5,248	57,448	418,970	32,996	1,319,112
						NPV $B	$ 10.49

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,489	444,825	437,202	428,627	420,863
2022	547,947	514,890	498,376	487,033	476,910
2023	552,092	505,896	486,266	470,784	450,668
2024	579,681	527,894	497,152	479,070	458,324
2025	1,182,397	1,106,899	1,040,215	995,018	918,182
2026	1,812,280	1,651,889	1,539,849	1,440,817	1,270,006
2027	1,722,565	1,588,799	1,489,501	1,390,912	1,252,726
2028	1,465,400	1,293,160	1,167,332	1,035,683	832,319
2029	1,414,056	1,236,111	1,117,426	983,875	766,726
2030	1,389,552	1,243,902	1,082,383	963,734	778,585
2031	1,373,886	1,196,764	1,075,862	961,729	747,127
2032	1,390,602	1,182,893	1,038,783	909,137	675,363
2033	1,315,205	1,138,621	1,004,740	871,181	636,277
2034	1,219,165	1,014,437	864,540	706,851	498,297
2035	1,564,493	1,413,584	1,309,824	1,206,689	1,057,771
2036	1,536,463	1,419,026	1,292,226	1,183,717	1,031,520
2037	1,554,620	1,408,706	1,298,569	1,175,218	985,765
2038	1,625,611	1,500,210	1,409,564	1,337,467	1,224,197
2039	1,586,462	1,442,135	1,367,593	1,292,714	1,168,762
2040	1,564,521	1,446,550	1,363,153	1,283,720	1,165,716
2041	1,542,242	1,404,250	1,319,097	1,227,750	1,139,752

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	12,126,611	11,130,703	10,408,193	9,804,281	9,172,532
NPV (2021-2030)	6,803,763	6,417,633	6,084,643	5,797,006	5,385,942
CAGR(2022-2030)	13.39%	11.66%	10.28%	8.70%	5.98%

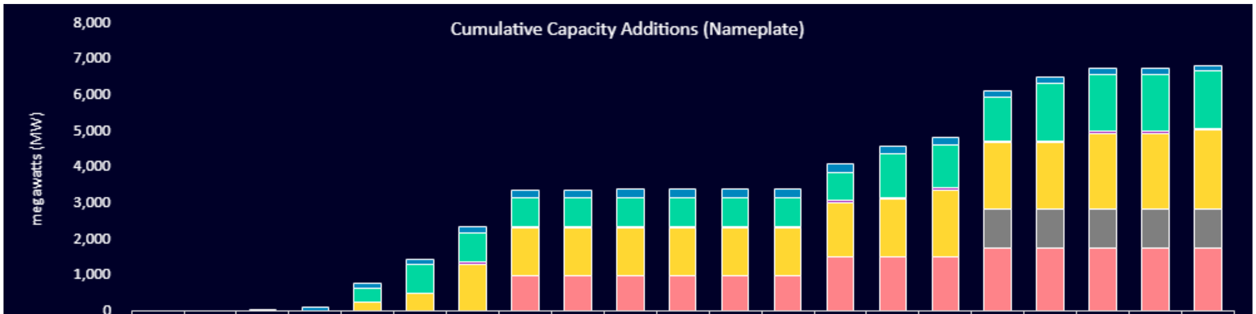


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct	**Total Lifecycle GHG CO_2e[1]**
2021	3,285,383	593,519	3,878,901	3,687,706
2022	3,318,093	1,492,757	4,810,850	4,618,381
2023	1,696,305	714,442	2,410,747	2,331,458
2024	1,605,108	717,650	2,322,758	2,247,665
2025	1,565,607	8,531	1,574,138	1,997,886
2026	1,554,375	1,401	1,555,776	2,465,795
2027	1,852,717	2,005	1,854,721	2,751,426
2028	1,166,585	2,499	1,169,084	2,101,010
2029	270,285	12,925	283,210	1,288,944
2030	230,427	5,636	236,062	1,238,768
2031	233,411	8,551	241,961	1,244,603
2032	203,750	15,863	219,613	1,223,554
2033	207,801	8,925	216,726	1,213,479
2034	217,987	6,813	224,800	1,222,458
2035	221,926	32,417	254,343	1,242,974
2036	229,896	54,589	284,485	1,276,395
2037	496,637	34,694	531,331	1,555,807
2038	508,121	394,777	902,898	1,928,428
2039	613,309	382,827	996,135	2,029,557
2040	483,494	395,379	878,873	1,912,560
2041	392,760	412,794	805,554	1,835,356

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-15: Portfolio Name: Preferred Portfolio



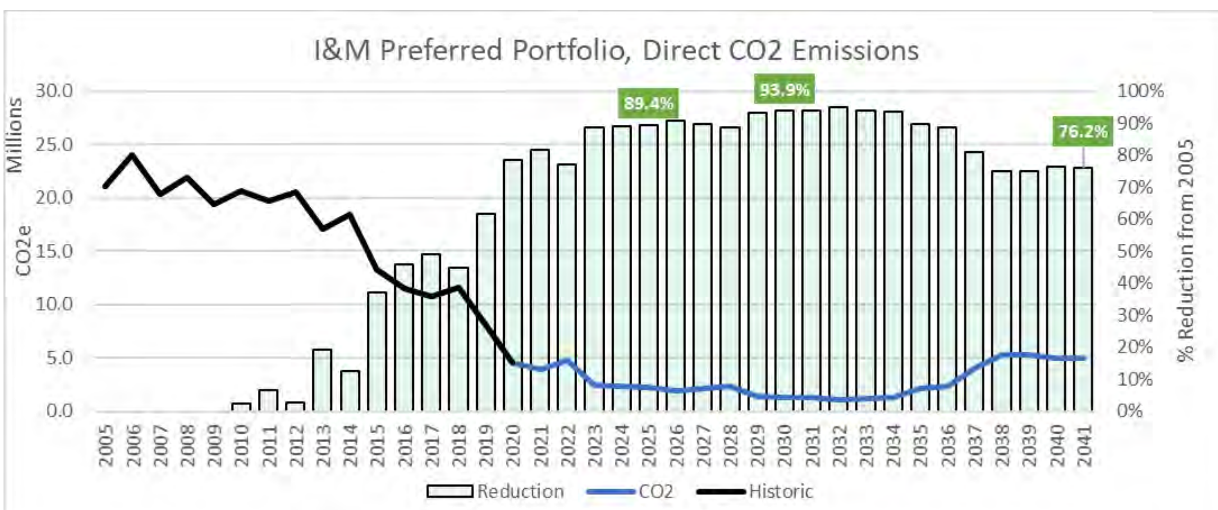
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	112	144	172	189	210	223	234	241	247	235	213	197	182	168	157	149	124
Wind	0	0	0	0	400	800	800	800	800	800	800	800	800	800	1,200	1,200	1,200	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Solar	0	0	0	0	250	500	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,500	1,600	1,850	1,850	1,850	2,100	2,100	2,200
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	0	0	1,000	1,000	1,000	1,000	1,000	1,000	1,500	1,500	1,500	1,750	1,750	1,750	1,750	1,750
Total	0	0	50	96	762	1,444	2,332	3,349	3,370	3,383	3,394	3,401	3,407	4,095	4,573	4,807	6,112	6,498	6,737	6,729	6,804

Mean IRP Cost to Serve Load ($,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	144,443	189,516	48	61,152	81,155	124,385	438,390
2022	131,271	222,721	59	53,885	81,710	177,863	504,089
2023	112,311	241,999	34	59,724	49,067	126,554	491,552
2024	114,056	253,214	45	59,599	47,622	126,932	506,219
2025	113,301	361,652	52	35,753	78,874	118,641	550,517
2026	118,014	481,810	56	14,966	129,832	96,357	581,362
2027	129,176	627,870	50	17,411	177,715	100,486	697,273
2028	156,993	619,830	20,241	15,828	236,173	101,039	677,655
2029	143,801	601,075	10,570	17,890	204,216	80,723	649,368
2030	140,527	596,437	9,290	17,045	190,780	72,576	644,723
2031	130,922	574,538	8,787	14,554	166,310	78,148	639,672
2032	132,419	558,941	7,390	18,087	172,472	72,340	616,113
2033	136,110	548,846	8,015	16,774	160,362	61,399	610,540
2034	136,320	594,110	11,533	18,052	238,890	49,425	569,685
2035	95,112	596,585	11,658	44,920	77,633	81,347	751,582
2036	90,536	620,582	11,654	43,366	78,741	96,692	783,507
2037	232,615	760,357	44,418	59,458	251,721	14,300	858,069
2038	178,571	747,344	45,619	31,737	68,518	106,094	1,041,190
2039	180,753	757,311	46,719	32,338	82,581	97,853	1,032,392
2040	174,106	732,731	45,002	32,197	71,988	107,274	1,019,322
2041	176,312	705,228	46,969	32,404	78,248	105,517	988,437
						NPV $B	**$ 6.76**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,514	444,916	437,102	428,572	421,083
2022	547,108	514,873	498,453	486,890	476,938
2023	552,080	505,863	486,466	470,930	450,675
2024	579,639	527,921	496,897	479,286	458,333
2025	642,060	578,589	542,486	517,505	486,248
2026	686,366	612,164	578,137	541,801	502,122
2027	817,184	739,421	691,002	652,131	590,595
2028	829,501	724,742	670,627	618,269	532,902
2029	822,999	703,387	636,299	583,670	523,468
2030	827,011	693,719	628,193	580,282	508,373
2031	842,589	690,463	615,591	573,407	512,316
2032	818,769	676,603	597,245	543,541	470,909
2033	805,338	654,714	598,576	536,346	466,057
2034	770,652	630,714	557,900	497,061	402,585
2035	946,530	803,890	730,149	675,764	633,002
2036	970,579	832,774	763,013	712,867	653,148
2037	1,064,884	911,192	839,803	784,873	722,717
2038	1,261,489	1,107,305	1,006,858	962,931	896,368
2039	1,235,398	1,083,039	1,005,203	960,606	891,052
2040	1,277,026	1,077,977	990,467	935,232	858,261
2041	1,182,606	1,052,249	965,028	913,705	842,609

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,097,095	7,105,997	6,621,375	6,231,914	5,895,490
NPV (2021-2030)	4,506,825	4,071,804	3,827,808	3,644,249	3,466,605
CAGR(2022-2030)	5.45%	3.90%	3.03%	2.03%	0.66%

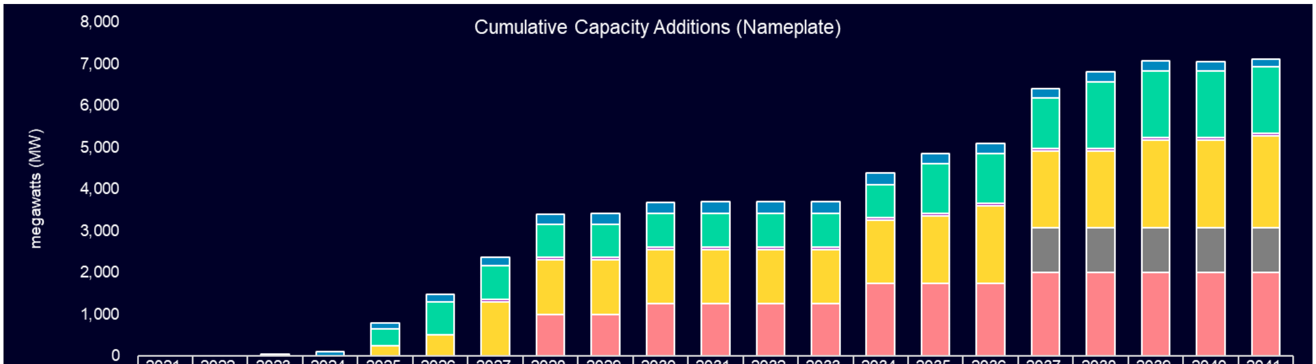


Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e**[1]
2021	3,288,302	593,074	3,881,376	3,689,955
2022	3,316,800	1,491,801	4,808,601	4,616,224
2023	1,700,556	713,037	2,413,594	2,333,940
2024	1,604,358	717,650	2,322,008	2,246,984
2025	1,674,176	557,572	2,231,748	2,210,291
2026	1,683,291	238,291	1,921,582	1,948,750
2027	1,923,804	208,947	2,132,751	2,243,589
2028	2,107,020	244,839	2,351,859	1,605,478
2029	1,191,191	214,944	1,406,135	1,756,660
2030	1,034,606	257,342	1,291,948	1,623,259
2031	931,595	348,998	1,280,593	1,597,097
2032	803,138	258,611	1,061,748	1,363,743
2033	883,320	352,573	1,235,893	1,543,513
2034	1,128,919	186,566	1,315,485	1,680,460
2035	1,167,023	991,971	2,158,994	2,549,272
2036	1,147,102	1,212,125	2,359,227	2,776,447
2037	3,865,740	170,117	4,035,857	5,347,449
2038	3,916,618	1,327,267	5,243,885	6,586,721
2039	4,058,104	1,217,233	5,275,337	6,654,828
2040	3,668,364	1,338,488	5,006,853	6,341,131
2041	3,642,442	1,383,251	5,025,693	6,371,141

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-16: Portfolio Name: OVEC 2030



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
EE	0	0	50	96	136	170	204	234	260	278	293	288	283	279	253	247	241	242	244	221	180
Wind	0	0	0	0	400	800	800	800	800	800	800	800	800	800	1,200	1,200	1,200	1,600	1,600	1,600	1,600
Storage	0	0	0	0	0	0	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
Solar	0	0	0	0	250	500	1,300	1,300	1,300	1,300	1,300	1,300	1,300	1,500	1,600	1,850	1,850	1,850	2,100	2,100	2,200
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,070	1,070	1,070	1,070	1,070
Gas Peaker	0	0	0	0	0	0	0	1,000	1,000	1,250	1,250	1,250	1,250	1,750	1,750	1,750	2,000	2,000	2,000	2,000	2,000
Total	0	0	50	96	786	1,470	2,364	3,394	3,420	3,688	3,703	3,698	3,693	4,389	4,863	5,107	6,421	6,822	7,074	7,051	7,110

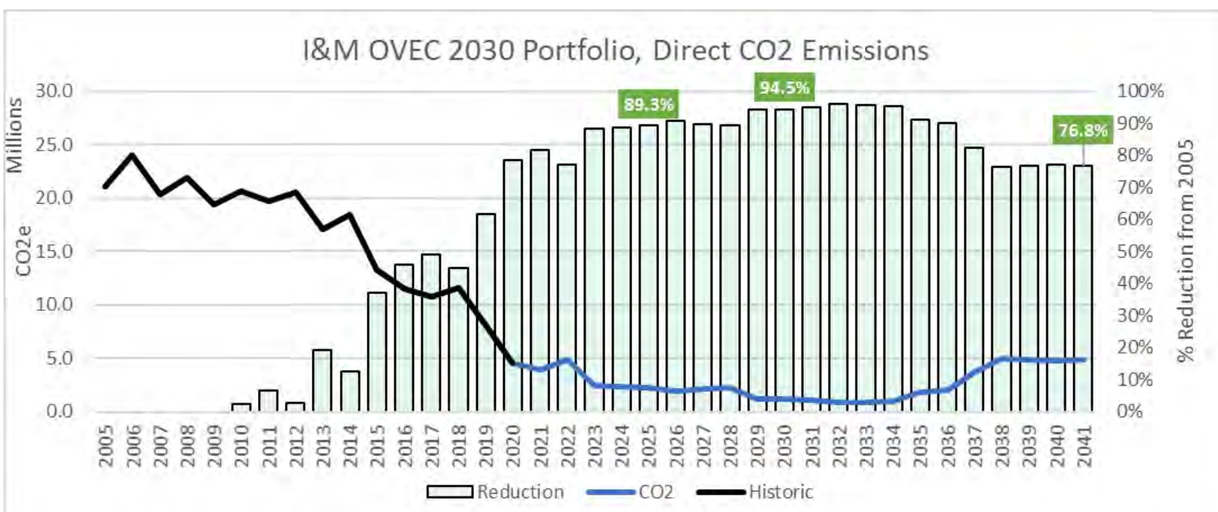
Mean IRP Cost to Serve Load ($,000)

	Fuel Cost	Fixed Cost	Emissions Cost	Variable O&M	Energy Export Revenue	Energy Import Cost	Cost to Serve Load
2021	$ 144,443	$ 189,516	$ 48	$ 61,152	$ 81,155	$ 124,385	$ 438,390
2022	$ 131,895	$ 222,721	$ 59	$ 53,915	$ 83,364	$ 177,803	$ 503,027
2023	$ 112,694	$ 241,999	$ 35	$ 59,739	$ 50,333	$ 126,745	$ 490,876
2024	$ 114,702	$ 253,214	$ 46	$ 59,630	$ 49,184	$ 127,215	$ 505,617
2025	$ 113,744	$ 361,653	$ 52	$ 35,775	$ 80,529	$ 118,865	$ 549,552
2026	$ 118,412	$ 481,810	$ 57	$ 14,985	$ 132,588	$ 96,684	$ 579,352
2027	$ 129,638	$ 627,870	$ 49	$ 17,434	$ 181,179	$ 100,802	$ 694,610
2028	$ 161,397	$ 619,830	$ 21,513	$ 15,953	$ 245,684	$ 101,044	$ 674,052
2029	$ 146,550	$ 601,075	$ 10,894	$ 17,939	$ 209,955	$ 80,666	$ 646,896
2030	$ 150,362	$ 618,206	$ 11,866	$ 17,278	$ 202,294	$ 70,812	$ 665,814
2031	$ 137,794	$ 595,816	$ 10,788	$ 14,731	$ 170,833	$ 76,035	$ 663,307
2032	$ 138,529	$ 579,749	$ 9,040	$ 18,244	$ 176,329	$ 70,447	$ 639,184
2033	$ 137,452	$ 569,206	$ 8,135	$ 16,795	$ 156,925	$ 59,874	$ 634,414
2034	$ 137,894	$ 614,039	$ 11,462	$ 18,077	$ 235,324	$ 47,588	$ 593,219
2035	$ 97,129	$ 616,102	$ 11,949	$ 44,955	$ 76,740	$ 82,388	$ 775,483
2036	$ 92,281	$ 639,704	$ 11,762	$ 43,395	$ 77,424	$ 97,813	$ 807,177
2037	$ 234,875	$ 779,098	$ 44,793	$ 59,517	$ 247,826	$ 13,770	$ 881,060
2038	$ 181,018	$ 765,720	$ 46,006	$ 31,810	$ 67,072	$ 107,638	$ 1,065,121
2039	$ 182,690	$ 775,221	$ 47,025	$ 32,391	$ 80,086	$ 100,149	$ 1,057,391
2040	$ 176,602	$ 750,309	$ 45,411	$ 32,267	$ 72,384	$ 107,878	$ 1,040,083
2041	$ 178,490	$ 722,379	$ 47,334	$ 32,461	$ 79,985	$ 104,516	$ 1,005,472
						NPV $B	**$ 6.85**

Stochastic Range IRP Cost to Serve Load (2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
2021	463,514	444,916	437,102	428,572	421,083
2022	547,631	514,224	497,556	486,109	475,318
2023	552,031	504,930	485,025	470,275	449,121
2024	579,666	527,205	496,165	478,273	457,236
2025	641,697	577,065	540,843	517,155	483,925
2026	685,162	611,001	576,490	539,000	499,773
2027	815,613	738,099	687,299	648,160	584,901
2028	822,350	722,130	669,567	615,651	528,500
2029	822,568	701,458	633,942	579,330	517,020
2030	844,693	717,234	650,780	600,935	533,102
2031	864,396	713,522	644,164	598,474	529,441
2032	841,569	697,028	616,648	563,960	489,417
2033	826,746	680,978	624,201	558,534	493,744
2034	793,973	654,199	579,825	517,534	424,386
2035	975,821	826,277	754,464	701,201	655,337
2036	1,006,553	856,723	784,188	733,122	679,543
2037	1,083,239	933,247	863,160	803,508	742,795
2038	1,290,581	1,130,483	1,027,712	987,128	915,674
2039	1,260,314	1,110,508	1,033,784	980,022	909,944
2040	1,296,981	1,095,851	1,012,784	955,065	874,191
2041	1,196,901	1,069,206	982,016	930,512	859,720

Stochastic Range IRP Cost to Serve Load (NPV 2019 $,000)					
	95th Percentile	75th Percentile	50th Percentile	25th Percentile	5th Percentile
NPV (2021-2041)	8,178,946	7,207,269	6,718,752	6,323,231	5,978,044
NPV (2021-2030)	4,517,156	4,079,581	3,832,092	3,641,178	3,463,925
CAGR(2022-2030)	6%	4%	4%	3%	1%

Supplemental Analysis for Full Portfolio Cost related to required OVEC Debt and Other Cost Obligations are found in Confidential Appendix Volume 3:



Direct and Lifecycle Emissions (tons CO_2), Stochastic				
Year	**Direct I&M**	**Imports (CO_2e)**	Total Direct + **Imports**	**Total Lifecycle GHG CO_2e**[1]
2021	3,288,302	593,074	3,881,376	3,689,946
2022	3,372,462	1,476,830	4,849,292	4,656,149
2023	1,741,250	706,495	2,447,745	2,367,698
2024	1,651,312	714,215	2,365,527	2,288,559
2025	1,710,094	555,294	2,265,389	2,242,871
2026	1,724,378	235,568	1,959,946	1,986,663
2027	1,970,243	205,624	2,175,867	2,286,123
2028	2,003,362	240,613	2,243,975	2,758,283
2029	1,003,040	211,371	1,214,412	1,820,518
2030	904,569	261,760	1,166,328	1,734,517
2031	678,204	366,472	1,044,676	1,551,196
2032	586,859	273,226	860,084	1,326,138
2033	543,303	369,820	913,123	1,355,343
2034	793,077	201,400	994,477	1,483,559
2035	831,113	1,036,235	1,867,348	2,390,395
2036	803,064	1,258,074	2,061,137	2,605,471
2037	3,523,975	182,983	3,706,958	5,128,328
2038	3,565,772	1,379,461	4,945,233	6,400,895
2039	3,605,665	1,291,320	4,896,985	6,392,894
2040	3,439,102	1,364,356	4,803,458	6,248,925
2041	3,537,038	1,371,751	4,908,789	6,393,242

2005 Baseline Direct I&M Emissions (tons CO_2): 21,134,511

[1] Based on NREL GHG emissions rates shown in Exhibit C-23

Exhibit C-17: Scenario Power Prices (2019$)

Average ($/MWh) Year	Reference Average	RTA Average	ER Average
2021	28.5	28.5	28.5
2022	28.6	28.6	28.6
2023	27.2	27.2	27.2
2024	26.6	26.6	26.6
2025	26.8	26.6	26.6
2026	27.0	26.7	26.9
2027	27.3	27.1	27.3
2028	34.0	33.7	33.9
2029	33.7	33.4	33.5
2030	32.5	32.2	32.4
2031	31.4	31.1	31.3
2032	31.0	30.7	30.8
2033	31.4	31.1	31.3
2034	31.5	31.1	31.3
2035	32.0	31.5	31.7
2036	31.9	31.1	31.4
2037	31.6	30.9	31.4
2038	32.3	31.2	31.8
2039	32.2	31.2	31.8
2040	32.2	31.0	31.3
2041	32.0	30.8	31.1

On Peak Year	Reference Average	RTA Average	ER Average
2021	30.6	30.6	30.6
2022	30.1	30.1	30.1
2023	28.6	28.6	28.6
2024	28.0	27.9	28.0
2025	27.9	27.7	27.8
2026	28.0	27.7	27.9
2027	28.3	28.0	28.2
2028	35.3	35.0	35.2
2029	35.1	34.8	35.0
2030	33.7	33.4	33.6
2031	32.5	32.2	32.4
2032	32.0	31.7	31.9
2033	32.5	32.2	32.4
2034	32.5	32.1	32.3
2035	33.1	32.6	32.8
2036	33.0	32.1	32.5
2037	32.7	31.9	32.5
2038	33.3	32.3	32.8
2039	33.3	32.4	32.9
2040	33.2	32.1	32.5
2041	33.2	32.1	32.3

Off Peak Year	Reference Average	RTA Average	ER Average
2021	26.3	26.3	26.3
2022	27.0	27.0	27.0
2023	25.7	25.7	25.7
2024	25.3	25.3	25.3
2025	25.6	25.5	25.5
2026	26.0	25.7	25.9
2027	26.4	26.2	26.3
2028	32.7	32.5	32.6
2029	32.2	32.0	32.1
2030	31.3	31.0	31.1
2031	30.3	30.1	30.2
2032	29.9	29.7	29.8
2033	30.3	30.0	30.2
2034	30.4	30.0	30.2
2035	30.9	30.5	30.6
2036	30.9	30.1	30.4
2037	30.6	29.8	30.3
2038	31.3	30.2	30.8
2039	31.1	30.1	30.6
2040	31.1	29.9	30.2
2041	30.9	29.5	29.9

Exhibit C-18: GWh Output by Unit/Portfolio

Reference (Original) Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,405	8,565	10,281	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,646	10,283	9,434	10,281	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,307	1,317	1,297	1,246	1,181	1,175	1,354	862	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,548	1,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	52,595	53,625	53,193	52,388	51,592
New CT	0	0	0	0	0	0	2,299	7,638	7,870	6,728	5,651	4,817	5,908	8,675	9,233	8,793	8,919	9,308	10,265	8,608	11,781
New Solar	0	0	0	0	13,080	26,159	26,159	26,224	26,159	26,159	26,159	26,224	26,159	26,159	26,159	26,224	26,159	26,159	26,159	26,224	26,159
New Wind	0	0	0	0	19,654	39,309	39,309	39,441	39,309	39,309	39,309	39,441	39,309	39,309	39,309	39,441	39,309	39,309	39,309	39,441	39,309
Storage	0	0	0	0	-11	-23	-23	-23	-23	-23	-23	-22	-22	-21	-21	-21	-20	-20	-19	-19	-18
EE Total (adjusted)	11	91	302	492	562	743	815	910	934	1,025	1,007	1,022	975	1,042	911	875	846	756	670	702	644

Rockport 1 - 2024 Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,188	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,405	8,565	10,281	9,438	9,637	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,304	1,321	1,315	1,212	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,551	1,548	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40,325	41,048	40,722	40,197	39,647
New CT	0	0	0	0	0	4,878	3,716	4,231	4,309	3,765	4,850	4,170	3,810	6,172	6,495	6,342	6,658	6,862	7,514	7,335	8,702
New Solar	0	0	0	0	9,385	14,906	19,875	19,925	19,875	19,875	19,875	19,925	19,875	19,875	19,875	19,925	19,875	19,875	19,875	19,925	19,875
New Wind	0	0	0	0	14,933	29,866	29,866	29,966	29,866	29,866	29,866	29,966	29,866	29,866	29,866	29,966	29,866	29,866	29,866	29,966	29,866
Storage	0	0	0	0	-30	-30	-31	-31	-32	-31	-30	-30	-30	-29	-29	-28	-27	-26	-26	-26	-24
EE Total (adjusted)	11	91	302	492	645	816	872	957	968	1,058	1,040	1,047	1,017	1,153	1,072	1,080	1,019	897	791	761	671

Rockport 1 - 2025 Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,438	9,637	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,306	1,318	1,310	1,247	1,099	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,549	1,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	44,710	45,380	45,007	44,360	43,660
New CT	0	0	0	0	0	2,717	2,082	4,685	4,787	4,184	3,638	3,120	4,235	6,854	7,212	7,040	6,179	6,400	6,999	7,039	8,317
New Solar	0	0	0	0	11,049	22,097	22,097	22,152	22,097	22,097	22,097	22,152	22,097	22,097	23,325	25,229	28,235	28,235	28,235	29,536	30,691
New Wind	0	0	0	0	16,602	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205
Storage	0	0	0	0	-33	-43	-44	-44	-45	-44	-43	-42	-42	-41	-41	-40	-38	-37	-37	-37	-35
EE Total (adjusted)	11	91	302	492	645	815	870	955	965	1,048	1,024	1,025	976	1,042	911	875	846	756	670	702	644

Rockport 1 - 2026 Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,308	1,319	1,308	1,247	1,214	1,084	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,548	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43,748	44,535	44,193	43,601	43,009
New CT	0	0	0	0	0	2,678	4,045	4,596	4,690	4,103	3,559	3,058	4,153	6,694	7,046	6,880	6,074	6,287	6,879	6,904	8,151
New Solar	0	0	0	0	10,781	16,770	21,562	21,615	21,562	21,562	21,562	21,615	21,562	21,562	21,562	21,615	21,562	21,562	21,562	21,615	21,562
New Wind	0	0	0	0	16,200	32,400	32,400	32,509	32,400	32,400	32,400	32,509	32,400	32,400	32,400	32,509	32,400	32,400	32,400	32,509	32,400
Storage	0	0	0	0	-9	-9	-10	-9	-10	-9	-9	-9	-9	-9	-9	-8	-8	-8	-8	-8	-7
EE Total (adjusted)	11	91	302	492	563	745	816	913	937	1,035	1,023	1,044	1,016	1,153	1,072	1,080	1,019	897	791	759	669

Cook 2050+ Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	9,164	9,189	9,164	9,164	9,164	9,189	9,164
Donald C Cook 2	9,404	8,564	10,281	9,437	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	10,284	10,284	10,312	10,284
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,304	1,319	1,309	1,248	1,213	1,204	1,378	892	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,550	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	2,600	8,685	8,900	7,788	6,755	5,803	5,295	5,240	4,996	4,838	4,740	4,338	4,759	3,995	4,840
New Solar	0	0	0	0	13,789	27,579	27,579	27,647	27,579	27,579	27,579	27,647	27,579	27,579	27,579	27,647	27,579	27,579	27,579	27,647	27,579
New Wind	0	0	0	0	20,721	41,442	41,442	41,581	41,442	41,442	41,442	41,581	41,442	41,442	41,442	41,581	41,442	41,442	41,442	41,581	41,442
Storage	0	0	0	0	-12	-24	-24	-24	-25	-24	-24	-23	-23	-23	-22	-22	-21	-21	-20	-20	-19
EE Total (adjusted)	11	91	302	492	562	743	815	910	934	1,025	1,007	1,022	975	1,042	911	875	846	756	642	673	617

Cook 2050+ and No Gas Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,389	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	9,164	9,189	9,164	9,164	9,164	9,189	9,164
Donald C Cook 2	9,404	8,564	10,281	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	10,284	10,284	10,312	10,284
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,308	1,317	1,307	1,249	1,213	1,195	1,373	893	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Solar	0	0	0	0	11,118	22,235	22,235	22,291	22,235	22,235	22,235	22,291	22,235	22,235	22,235	22,291	22,235	22,235	22,235	22,291	22,235
New Wind	0	0	0	0	16,706	33,412	33,412	33,525	33,412	33,412	33,412	33,525	33,412	33,412	33,412	33,525	33,412	33,412	33,412	33,525	33,412
Storage	0	0	0	0	-9	-19	-20	-46	-47	-46	-49	-47	-52	-52	-52	-50	-48	-47	-47	-47	-45
EE Total (adjusted)	11	91	302	492	634	814	891	1,022	1,054	1,162	1,143	1,122	1,036	1,083	932	886	853	759	645	675	619

Reference with Expanded Build Limits Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,437	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,310	1,319	1,309	1,249	1,208	1,204	1,365	877	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,283	36,621	36,281	35,802	35,198
New CT	0	0	0	0	0	0	0	1,855	1,905	1,670	1,452	1,253	1,145	3,350	4,615	4,503	4,984	5,067	5,556	4,717	5,590
New Solar	0	0	0	0	9,030	18,059	27,089	27,156	27,089	27,089	27,089	27,156	27,089	29,597	29,597	29,671	29,597	29,597	29,597	29,671	29,597
New Wind	0	0	0	0	13,569	27,137	40,706	40,842	40,706	40,706	40,706	40,842	40,706	40,706	40,706	40,842	40,706	40,706	40,706	40,842	40,706
Storage	0	0	0	0	-8	-16	-24	-24	-24	-24	-24	-23	-23	-23	-23	-22	-21	-21	-20	-20	-19
EE Total (adjusted)	11	91	302	492	587	773	846	971	1,010	1,120	1,114	1,137	1,077	1,205	1,033	966	915	804	712	708	648

Reference' Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,405	8,564	10,281	9,437	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,281	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,304	1,322	1,314	1,250	1,219	1,201	1,366	887	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,548	1,545	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	37,422	38,068	37,752	37,260	36,707
New CT	0	0	0	0	0	0	1,746	5,827	5,970	5,220	4,529	3,893	4,695	6,870	7,210	7,037	7,199	7,368	8,058	6,824	8,060
New Solar	0	0	0	0	5,120	10,241	18,433	18,479	18,433	18,433	18,433	18,479	18,433	18,433	18,433	18,993	18,945	18,945	18,945	18,993	19,970
New Wind	0	0	0	0	13,850	27,699	27,699	27,792	27,699	27,699	27,699	27,792	27,699	27,699	27,699	27,792	27,699	27,699	27,699	27,792	27,699
Storage	0	0	0	0	0	0	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-5	-5	-5	-5
EE Total (adjusted)	11	91	302	492	634	814	891	1,022	1,054	1,162	1,143	1,123	1,038	1,086	940	941	945	900	856	895	795

Rapid Technology Advancement Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,162	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,404	9,644	10,282	9,431	10,271	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	8
Rockport 1	1,303	1,324	1,313	1,249	1,216	1,204	1,368	880	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,554	1,549	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	6	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	1,807	6,029	6,143	5,388	4,665	4,017	3,655	5,761	5,976	6,356	7,630	7,575	8,449	6,891	8,376
New Solar	0	0	0	0	9,774	19,548	19,548	19,596	19,548	19,548	19,548	19,596	19,548	20,634	23,348	26,128	30,950	30,950	30,950	31,027	30,950
New Wind	0	0	0	0	14,687	29,374	29,374	29,472	29,374	29,374	29,374	29,472	29,374	46,183	46,183	63,981	81,359	98,947	98,947	117,510	121,672
Storage	0	0	0	0	-8	-17	-17	-17	-18	-17	-17	-17	-17	-16	-16	-16	-19	-19	-18	-18	-18
EE Total (adjusted)	11	91	306	500	573	753	833	875	910	1,017	1,006	1,023	983	1,133	1,053	1,038	1,005	897	792	786	687

Enhanced Regulation Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,437	9,637	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,279	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	8
Rockport 1	1,304	1,318	1,211	1,154	1,078	1,100	1,275	826	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,551	1,532	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	1,526	5,046	5,139	4,476	3,886	3,339	3,057	4,822	4,995	5,475	6,782	6,679	7,375	5,741	6,888
New Solar	0	0	0	0	7,871	15,742	15,742	15,781	15,742	15,742	15,742	15,781	15,742	16,616	18,803	21,041	24,925	24,925	24,925	24,987	24,925
New Wind	0	0	0	0	11,827	23,655	23,655	23,734	23,655	23,655	23,655	23,734	23,655	37,191	37,191	51,525	65,519	79,683	79,683	94,632	97,983
Storage	0	0	0	0	-7	-14	-14	-14	-14	-14	-14	-13	-13	-13	-13	-13	-12	-12	-11	-11	-11
EE Total (adjusted)	11	91	302	492	628	824	887	1,000	1,028	1,133	1,095	1,092	1,026	1,152	1,070	1,072	1,077	961	847	834	725

Rockport 1 - 2024 NTG Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,188	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,565	10,280	9,438	9,637	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,305	1,324	1,310	1,211	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,546	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	44,752	45,538	45,151	44,537	43,906
New CT	0	0	0	0	0	2,727	2,084	4,692	4,781	4,175	5,384	4,626	4,220	6,850	7,195	7,019	7,372	7,571	8,301	8,096	9,614
New Solar	0	0	0	0	11,049	22,097	22,097	22,152	22,097	22,097	22,097	22,152	22,097	22,097	22,097	22,152	22,097	22,097	22,097	22,152	22,097
New Wind	0	0	0	0	16,602	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205	33,205	33,205	33,316	33,205
Storage	0	0	0	0	-33	-43	-44	-44	-45	-44	-43	-42	-42	-41	-42	-40	-38	-37	-37	-37	-35
EE Total (adjusted)	11	91	271	434	573	689	724	822	889	989	1,007	1,088	1,080	1,311	1,278	1,341	1,409	1,328	1,261	1,350	1,287

Rockport 1 - 2026 NTG Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,280	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,310	1,319	1,312	1,247	1,213	1,085	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,550	1,551	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	42,420	43,156	42,785	42,198	41,617
New CT	0	0	0	0	0	2,598	3,934	4,469	4,556	3,979	3,461	2,974	4,036	6,530	6,873	6,708	5,906	6,098	6,668	5,668	7,906
New Solar	0	0	0	0	10,464	17,439	20,927	20,980	20,927	20,927	20,927	20,980	20,927	20,927	20,927	20,980	20,927	20,927	20,927	20,980	20,927
New Wind	0	0	0	0	15,724	31,447	31,447	31,553	31,447	31,447	31,447	31,553	31,447	31,447	31,447	31,553	31,447	31,447	31,447	31,553	31,447
Storage	0	0	0	0	-9	-11	-11	-12	-12	-11	-11	-11	-11	-11	-11	-10	-10	-10	-10	-9	-9
EE Total (adjusted)	11	91	271	434	527	654	695	797	868	966	948	993	950	1,159	1,132	1,223	1,342	1,306	1,278	1,395	1,326

Rapid Technology Advancement NTG Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,162	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,438	9,636	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,404	9,644	10,282	9,432	10,274	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	8
Rockport 1	1,309	1,318	1,313	1,242	1,222	1,202	1,366	876	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,550	1,547	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	6	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	1,567	5,229	5,328	4,669	4,039	3,473	3,164	5,042	5,171	5,774	7,145	7,291	8,123	6,336	7,584
New Solar	0	0	0	0	7,529	15,059	16,941	16,983	16,941	16,941	16,941	16,983	16,941	17,882	20,235	22,645	27,294	27,294	27,294	27,834	27,765
New Wind	0	0	0	0	12,729	25,457	25,457	25,543	25,457	25,457	25,457	25,543	25,457	32,741	40,025	55,450	70,511	70,511	70,511	86,549	90,206
Storage	0	0	0	0	-5	-11	-11	-11	-11	-11	-11	-11	-11	-11	-11	-10	-14	-13	-13	-13	-13
EE Total (adjusted)	10	91	274	441	568	748	820	961	1,032	1,220	1,247	1,308	1,278	1,510	1,457	1,492	1,558	1,460	1,384	1,475	1,393

Reference with No Renewable Limits Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,390	8,396	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,437	9,637	10,284	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,279	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,309	1,321	1,309	1,248	1,147	1,132	1,343	864	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,551	1,548	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,779	1,797	1,946	2,457	2,872
New Solar	0	0	0	0	25,125	50,249	50,249	50,375	50,249	50,249	50,249	50,375	50,249	50,249	50,249	50,375	50,249	50,249	50,249	50,375	50,249
New Wind	0	0	0	0	42,474	84,947	84,947	85,232	84,947	84,947	84,947	85,232	84,947	84,947	84,947	85,232	84,947	84,947	84,947	85,232	84,947
Storage	0	0	0	0	-24	-50	-49	-50	-50	-49	-49	-47	-47	-47	-46	-45	-43	-43	-42	-41	-40
EE Total (adjusted)	11	91	302	492	562	743	815	910	934	1,025	1,007	1,022	975	1,042	911	875	846	756	670	702	644

Preferred Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,394	9,187	8,389	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,281	9,437	9,636	10,283	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,645	10,283	9,433	10,280	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,310	1,320	1,313	1,248	1,233	1,220	1,391	900	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,548	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,412	36,894	36,490	35,984	35,454
New CT	0	0	0	0	0	0	0	7,726	7,885	6,884	5,969	5,126	5,791	7,841	8,151	7,917	7,919	7,990	8,744	7,395	8,787
New Solar	0	0	0	0	2,483	4,966	12,912	12,944	12,912	12,912	12,912	12,944	12,912	14,898	15,891	18,420	18,374	18,374	20,857	20,909	21,850
New Wind	0	0	0	0	6,716	13,432	13,432	13,477	13,432	13,432	13,432	13,477	13,432	13,432	20,148	20,216	20,148	26,864	26,864	26,954	26,864
Storage	0	0	0	0	0	0	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-5	-5	-5	-5	-5
EE Total (adjusted)	11	91	302	492	634	814	891	1,022	1,054	1,162	1,143	1,123	1,038	1,086	940	941	945	900	856	895	795

OVEC 2030 Portfolio Average Output by Unit (GWh)																					
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
AEP IM Hydro	113	113	113	113	113	113	113	113	113	113	96	96	96	87	87	87	5	5	5	5	5
Deer Creek	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	4	3	3	3	3	3
Donald C Cook 1	9,162	7,809	8,393	9,187	8,389	8,395	9,164	8,417	8,397	9,164	8,389	8,614	9,163	9,163	0	0	0	0	0	0	0
Donald C Cook 2	9,404	8,564	10,280	9,437	9,636	10,283	9,406	9,675	10,284	9,411	9,637	10,312	9,405	9,646	10,283	9,433	10,281	0	0	0	0
Olive	8	8	8	9	7	9	8	8	7	9	7	8	8	8	7	7	9	8	8	7	9
Rockport 1	1,310	1,331	1,332	1,278	1,253	1,239	1,413	971	0	0	0	0	0	0	0	0	0	0	0	0	0
Rockport 2	1,552	1,567	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
St. Joesph Solar	47	44	46	43	47	43	47	45	46	44	47	47	44	46	46	48	43	47	44	47	44
Twin Branch	4	3	4	3	4	3	4	4	4	3	4	4	3	4	4	4	3	4	3	4	3
Watervliet	6	7	7	7	6	7	6	6	6	7	6	6	7	7	6	6	7	6	7	6	7
New CCGT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36,502	37,031	36,584	36,106	35,549
New CT	0	0	0	0	0	0	0	8,164	8,296	8,838	7,452	6,442	5,969	8,045	8,440	8,158	8,125	8,171	8,894	7,594	8,972
New Solar	0	0	0	0	2,483	4,966	12,912	12,944	12,912	12,912	12,912	12,944	12,912	14,898	15,891	18,420	18,374	18,374	20,857	20,909	21,850
New Wind	0	0	0	0	6,716	13,432	13,432	13,477	13,432	13,432	13,432	13,477	13,432	13,432	20,148	20,216	20,148	26,864	26,864	26,954	26,864
Storage	0	0	0	0	0	0	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6	-5	-5	-5	-5	-5
EE Total (adjusted)	11	91	302	492	634	814	891	1,022	1,054	1,162	1,143	1,123	1,038	1,086	940	941	945	900	856	895	795

Exhibit C-19: Capacity Position

UCAP (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference (Original)	4,424	4,437	4,247	3,700	4,278	4,801	4,974	4,089	4,100	4,107	4,104	4,124	4,347	3,811	3,736	3,695	3,815	3,829	3,821	3,667	3,879
Rockport 1 2024	4,424	4,437	4,832	2,445	3,258	4,013	4,129	4,033	4,040	4,047	4,274	4,294	4,289	3,760	3,673	3,618	3,735	3,748	3,734	3,805	3,778
Rockport 1 2025	4,424	4,437	4,832	3,700	3,281	4,028	3,962	4,094	4,097	4,098	4,089	4,103	4,320	3,779	3,728	3,728	3,690	3,700	3,687	3,789	3,798
Rockport 1 2026	4,424	4,437	4,247	3,700	4,279	3,784	4,120	4,033	4,047	4,060	4,063	4,089	4,320	3,796	3,713	3,663	3,555	3,573	3,563	3,636	3,615
Cook 2050+	4,424	4,437	4,832	3,700	4,278	4,801	4,974	4,089	4,100	4,107	4,104	4,124	4,117	4,109	4,034	3,993	4,010	4,024	4,013	3,859	3,842
Cook 2050+ and No Gas	4,424	4,437	4,832	3,700	4,290	4,817	4,766	3,943	3,949	3,988	4,017	4,019	4,033	4,009	3,911	3,844	3,849	3,852	3,828	3,661	3,628
Expanded Build Limits	4,424	4,437	4,247	3,700	4,284	4,812	5,243	4,080	4,096	4,107	4,109	4,131	4,125	3,674	3,804	3,742	3,863	3,879	3,867	3,710	3,686
Reference'	4,424	4,437	4,247	3,700	4,045	4,369	4,920	4,046	4,064	4,077	4,079	4,095	4,315	3,784	3,698	3,664	3,790	3,815	3,811	3,657	3,663
No Build Limits	4,424	4,437	4,247	3,700	5,687	7,406	7,125	5,515	5,519	5,519	5,509	5,523	5,509	4,506	4,424	4,376	3,713	3,720	3,705	3,774	3,749
Rapid Technology Advancement	4,424	4,437	4,834	3,702	4,280	4,805	4,982	4,095	4,112	4,124	4,127	4,151	4,148	3,742	3,750	4,109	3,726	3,828	3,820	3,751	3,756
Enhanced Regulation	4,424	4,437	4,247	3,700	4,167	4,651	4,722	4,024	4,042	4,054	4,458	4,476	4,467	3,702	3,650	3,688	3,686	3,791	3,803	3,736	3,716
Rockport 1 2024 N2G	4,425	4,438	4,833	2,447	3,282	4,022	3,949	4,077	4,088	4,087	4,314	4,332	4,323	3,797	3,715	3,665	3,779	3,790	3,777	3,848	3,824
Rockport 1 2026 N2G	4,425	4,438	4,248	3,701	4,283	3,838	4,128	4,037	4,057	4,060	4,054	4,072	4,293	3,771	3,702	3,659	3,555	3,579	3,577	3,426	3,632
Rapid Technology N2G	4,424	4,438	4,248	3,701	4,218	4,690	4,944	4,061	4,073	4,079	4,077	4,099	4,092	3,632	3,687	4,037	3,664	3,678	3,670	3,619	3,624
Preferred Portfolio	4,424	4,437	4,247	3,700	3,881	4,065	4,414	4,033	4,051	4,064	4,066	4,082	4,072	3,603	3,592	3,620	3,746	3,815	3,888	3,734	3,741
OVEC 2030	4,424	4,437	4,832	3,700	3,881	4,065	4,414	4,033	4,051	4,144	4,146	4,163	4,153	3,684	3,672	3,700	3,826	3,895	3,968	3,964	3,971
I&M PJM Obligation with FPR	**3,939**	**3,972**	**3,994**	**4,014**	**3,864**	**3,868**	**3,876**	**3,882**	**3,904**	**3,914**	**3,928**	**3,934**	**3,960**	**3,533**	**3,548**	**3,554**	**3,580**	**3,523**	**3,540**	**3,546**	**3,573**
Represents short term capacity purchase years																					

Exhibit C-20: Capacity Surplus

Capacity Surplus (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference (Original)	485	465	253	-314	414	933	1,098	207	196	193	176	190	387	278	188	141	235	306	281	121	306
Rockport 1 2024	485	465	838	-1,569	-606	145	253	151	136	133	346	360	329	227	125	64	155	225	194	259	205
Rockport 1 2025	485	465	838	-314	-583	160	86	212	193	184	161	169	360	246	180	174	110	177	147	243	225
Rockport 1 2026	485	465	253	-314	415	-84	244	151	143	146	135	155	360	263	165	109	-25	50	23	90	42
Cook 2050+	485	465	838	-314	414	933	1,098	207	196	193	176	190	157	576	486	439	430	501	473	313	269
Cook 2050+ and No Gas	485	465	838	-314	426	949	890	61	45	74	89	85	73	476	363	290	269	329	288	115	55
Expanded Build Limits	485	465	253	-314	420	944	1,367	198	192	193	181	197	165	141	256	188	283	356	327	164	113
Reference'	485	465	253	-314	181	501	1,044	164	160	163	151	161	355	251	150	110	210	292	271	111	90
No Build Limits	485	465	253	-314	1,823	3,538	3,249	1,633	1,615	1,605	1,581	1,589	1,549	973	876	822	133	197	165	228	176
Rapid Technology Advancement	485	465	840	-312	416	937	1,106	213	208	210	199	217	188	209	202	555	146	305	280	205	183
Enhanced Regulation	485	465	253	-314	303	783	846	142	138	140	530	542	507	169	102	134	106	268	263	190	143
Rockport 1 2024 N2G	486	466	839	-1,567	-582	154	73	195	184	173	386	398	363	264	167	111	199	267	237	302	251
Rockport 1 2026 N2G	486	466	254	-313	419	-30	252	155	153	146	126	138	333	238	154	105	-25	56	37	-120	59
Rapid Technology N2G	485	466	254	-313	354	822	1,068	179	169	165	149	165	132	99	139	483	84	155	130	73	51
Preferred Portfolio	485	465	253	-314	17	197	538	151	147	150	138	148	112	70	44	66	166	292	348	188	168
OVEC 2030	485	465	838	-314	17	197	538	151	147	230	218	229	193	151	124	146	246	372	428	418	398

Exhibit C-21: Exports as % of I&M Load

Exports (% of Load)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference (Original)	12%	12%	7%	7%	21%	42%	45%	43%	41%	40%	37%	39%	37%	51%	16%	14%	44%	9%	9%	8%	9%
Rockport 1 2024	12%	12%	7%	7%	16%	37%	41%	39%	39%	39%	38%	40%	37%	51%	17%	15%	45%	9%	9%	9%	9%
Rockport 1 2025	12%	12%	7%	7%	21%	39%	40%	39%	39%	39%	36%	39%	36%	51%	17%	16%	48%	11%	11%	12%	12%
Rockport 1 2026	12%	12%	7%	7%	21%	42%	42%	40%	41%	40%	38%	40%	38%	52%	18%	16%	45%	9%	9%	9%	9%
Cook 2050+	12%	12%	7%	7%	21%	42%	45%	44%	41%	40%	38%	40%	36%	49%	52%	48%	50%	51%	52%	50%	49%
Cook 2050+ and No Gas	12%	12%	7%	7%	21%	43%	44%	39%	37%	37%	34%	37%	34%	46%	49%	45%	47%	48%	49%	48%	46%
Expanded Build Limits	12%	12%	7%	7%	21%	43%	64%	60%	57%	57%	55%	57%	54%	73%	36%	33%	67%	24%	24%	22%	22%
Reference'	12%	12%	7%	7%	18%	36%	46%	44%	42%	41%	38%	40%	38%	52%	17%	16%	46%	10%	11%	9%	10%
No Renewable Limits	12%	12%	7%	7%	70%	146%	147%	142%	139%	138%	136%	139%	135%	157%	118%	113%	118%	72%	73%	73%	71%
Rapid Technology Advancement	12%	12%	7%	7%	21%	43%	45%	44%	41%	40%	37%	40%	36%	66%	31%	44%	67%	37%	39%	51%	53%
Enhanced Regulation	12%	12%	7%	7%	21%	42%	45%	44%	41%	41%	38%	40%	37%	67%	31%	45%	68%	38%	39%	51%	54%
Rockport 1 2024 N2G	12%	12%	7%	7%	16%	39%	39%	38%	39%	39%	38%	40%	37%	52%	17%	16%	46%	10%	10%	10%	10%
Rockport 1 2026 N2G	12%	12%	7%	7%	21%	43%	42%	40%	41%	40%	37%	40%	37%	53%	18%	16%	46%	10%	10%	9%	10%
Rapid Technology N2G	12%	12%	7%	7%	20%	41%	45%	44%	41%	41%	38%	41%	38%	61%	33%	47%	71%	29%	30%	41%	44%
Preferred Portfolio	12%	12%	7%	7%	12%	21%	29%	31%	28%	27%	25%	26%	24%	39%	13%	13%	41%	11%	13%	12%	12%
OVEC 2030	12%	12%	7%	8%	13%	21%	29%	32%	29%	28%	25%	27%	24%	38%	13%	13%	40%	11%	13%	12%	12%

Exhibit C-22: Imports as % of I&M Load

Imports (% of Load)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Reference (Original)	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	1%	8%	11%	1%	16%	15%	17%	17%
Rockport 1 2024	7%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	1%	7%	10%	1%	15%	15%	16%	17%
Rockport 1 2025	7%	16%	8%	8%	3%	1%	1%	1%	1%	1%	2%	1%	2%	1%	8%	10%	1%	14%	14%	15%	15%
Rockport 1 2026	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	1%	7%	10%	1%	15%	14%	16%	17%
Cook 2050+	7%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Cook 2050+ and No Gas	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	2%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%
Expanded Build Limits	7%	16%	8%	8%	3%	1%	0%	0%	0%	1%	1%	1%	1%	0%	4%	5%	1%	7%	7%	8%	9%
Reference'	7%	16%	8%	8%	4%	1%	1%	1%	1%	1%	1%	1%	2%	1%	8%	10%	1%	15%	14%	16%	16%
No Renewable Limits	7%	16%	8%	8%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	0%	4%	4%	4%	5%
Rapid Technology Advancement	7%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	0%	3%	3%	1%	6%	6%	3%	3%
Enhanced Regulation	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	0%	3%	3%	1%	6%	6%	3%	3%
Rockport 1 2024 N2G	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	1%	7%	10%	1%	14%	13%	15%	15%
Rockport 1 2026 N2G	7%	16%	8%	8%	3%	1%	1%	1%	1%	1%	2%	1%	2%	1%	7%	10%	1%	14%	13%	15%	15%
Rapid Technology N2G	6%	16%	8%	8%	3%	1%	1%	1%	1%	1%	1%	1%	2%	0%	3%	3%	1%	9%	8%	5%	5%
Preferred Portfolio	6%	16%	8%	8%	6%	2%	2%	2%	2%	2%	3%	2%	3%	2%	11%	13%	2%	15%	14%	15%	15%
OVEC 2030	6%	16%	8%	8%	6%	2%	2%	2%	2%	2%	3%	2%	3%	2%	11%	14%	2%	15%	14%	15%	15%

Exhibit C-23: GHG Emissions

Life Cycle GHG Emissions[1]
(grams of CO_2e per kWh)

	Specific Technology	Market
All Coal		1,002
Sub Critical	1,062	
Super Critical	863	
All Gas		474
Gas CT	599	
Gas CC[3]	481	
All Nuclear		16
Onshore Wind	12	12
All PV		54
Thin Film	35	
Crystalline	57	
All hydropower	7	7
Bio Power	43	43

Grams of CO_2e per purchased kWh: 374

Exhibit C-24: I&M CO_2 Profile - Direct Emissions, I&M Assets

I&M CO2 Profile - Direct Emissions -		Preferred Portfolio	Reference Portfolio	Reference ' Portfolio	Rockport '24 Portfolio	Rockport '25 Portfolio	Rockport '26 Portfolio	Cook 2050+ Portfolio	Cook 2050+ and No Gas Portfolio	Rapid Technology Portfolio	Enhanced Regulation Portfolio	Rockport '24 NTG Portfolio	Rockport '26 NTG Portfolio	RTA NTG Portfolio	Expanded Build Limits Portfolio	Unlimited Renewable Portfolio	OVEC 2030 Portfolio
Type	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2
Unit	short tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons
2005	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511
2006	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204
2007	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761
2008	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034
2009	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586
2010	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516
2011	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745
2012	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940
2013	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824
2014	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380
2015	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452
2016	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979
2017	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307
2018	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974
2019	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326
2020	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809
2021		3,288,302	3,280,559	3,277,210	3,281,135	3,280,348	3,285,838	3,281,421	3,284,986	3,282,883	3,280,303	3,282,847	3,286,018	3,284,393	3,304,306	3,285,383	3,288,302
2022		3,316,800	3,314,629	3,315,742	3,317,585	3,315,794	3,316,024	3,317,665	3,314,691	3,322,290	3,297,643	3,318,821	3,318,504	3,313,916	3,333,238	3,318,093	3,372,462
2023		1,700,556	1,681,880	1,701,152	1,701,951	1,696,776	1,695,321	1,695,822	1,693,924	1,700,516	1,593,388	1,696,953	1,698,625	1,700,421	1,703,577	1,696,305	1,741,250
2024		1,604,358	1,602,365	1,607,371	1,566,831	1,603,455	1,603,790	1,604,716	1,605,888	1,604,406	1,506,868	1,566,335	1,604,223	1,597,095	1,613,637	1,605,108	1,651,312
2025		1,674,176	1,604,310	1,657,547	385,949	1,531,215	1,650,732	1,650,220	1,650,259	1,651,229	1,509,051	386,089	1,650,086	1,657,375	1,652,725	1,565,607	1,710,094
2026		1,683,291	1,618,204	1,657,861	909,996	656,834	1,789,698	1,658,558	1,649,566	1,655,844	1,557,081	657,838	1,790,972	1,654,190	1,658,366	1,554,375	1,724,378
2027		1,923,804	2,048,934	2,087,829	853,147	661,864	854,349	2,098,024	1,899,178	2,079,709	2,003,211	662,099	855,241	2,077,451	1,883,814	1,852,717	1,970,243
2028		2,107,020	1,769,126	1,850,665	713,436	711,473	713,887	1,853,545	1,206,110	1,823,861	1,799,562	711,866	714,865	1,820,183	1,395,760	1,166,585	2,003,362
2029		1,191,191	892,199	946,624	725,775	724,880	727,171	943,606	278,978	921,981	953,622	724,306	727,801	922,573	491,939	270,285	1,003,040
2030		1,034,606	759,807	822,195	628,542	628,324	630,405	820,316	238,335	802,497	825,597	627,117	630,194	802,332	425,525	230,427	904,569
2031		931,595	673,825	747,385	743,187	579,583	580,488	745,269	240,384	728,158	750,522	742,143	581,220	727,693	403,485	233,411	678,204
2032		803,138	578,791	645,006	641,560	500,363	501,449	643,023	209,458	629,066	647,980	640,377	502,193	627,781	350,141	203,750	586,859
2033		883,320	668,184	738,387	608,016	607,889	609,893	608,724	213,062	594,224	614,781	606,105	610,415	593,718	341,792	207,801	543,303
2034		1,128,919	896,927	991,314	862,557	861,860	862,470	614,759	223,080	823,286	852,956	861,133	865,645	830,159	602,978	217,987	793,077
2035		1,167,023	945,704	1,033,066	899,898	898,991	899,870	592,601	219,292	848,607	878,455	897,108	903,316	847,262	750,901	221,926	831,113
2036		1,147,102	917,074	1,021,132	891,569	890,136	891,486	588,552	226,897	887,419	943,324	888,415	894,351	925,221	745,847	229,896	803,064
2037		3,865,740	3,610,996	3,748,907	3,632,500	3,510,479	3,522,956	605,703	251,394	1,037,683	1,135,211	3,624,450	3,521,159	1,111,600	3,482,797	496,637	3,523,975
2038		3,916,618	3,696,935	3,822,248	3,709,711	3,579,362	3,599,690	575,860	251,689	1,038,555	1,128,048	3,698,259	3,594,671	1,138,528	3,525,291	508,121	3,565,772
2039		4,058,104	3,832,305	3,961,586	3,840,866	3,697,646	3,720,360	689,599	333,963	1,211,137	1,302,652	3,827,870	3,712,188	1,325,028	3,640,829	613,309	3,605,665
2040		3,668,364	3,475,092	3,590,717	3,589,828	3,465,388	3,488,701	441,495	142,903	861,795	890,909	3,574,630	3,379,095	909,591	3,313,559	483,494	3,439,102
2041		3,642,442	3,543,078	3,541,305	3,547,177	3,395,376	3,423,778	361,783	0	883,272	902,005	3,531,076	3,415,260	922,818	3,221,981	392,760	3,537,038
		82.8%	83.2%	83.2%	83.2%	83.9%	83.8%	98.3%	100.0%	95.8%	95.7%	83.3%	83.8%	95.6%	84.8%	98.1%	83.3%

Exhibit C-25: I&M CO_2 Profile - Direct Emissions including Imports

Portfolio		Preferred Portfolio	Reference Portfolio	Reference ' Portfolio	Rockport '24 Portfolio	Rockport '25 Portfolio	Rockport '26 Portfolio	Cook 2050+ Portfolio	Cook 2050+ and No Gas Portfolio	Rapid Technology Portfolio	Enhanced Regulation Portfolio	Rockport '24 NTG Portfolio	Rockport '26 NTG Portfolio	RTA NTG Portf	Expanded Build Limits Portfolio	Unlimited Renewable Portfolio	OVEC 2030 Portfolio
Type	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2
Unit	short tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons
2005	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511
2006	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204
2007	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761
2008	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034
2009	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586
2010	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516
2011	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745
2012	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940
2013	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824
2014	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380
2015	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452
2016	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979
2017	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307
2018	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974
2019	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326
2020	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809
2021		3,881,376	3,873,697	3,870,941	3,875,211	3,873,936	3,878,281	3,876,498	3,878,269	3,876,450	3,872,840	3,875,476	3,879,618	3,877,638	3,900,838	3,878,901	3,881,376
2022		4,808,601	4,808,564	4,809,398	4,810,864	4,807,835	4,809,565	4,809,525	4,807,076	4,812,946	4,807,672	4,810,468	4,810,449	4,807,505	4,832,464	4,810,850	4,849,292
2023		2,413,594	2,396,835	2,414,847	2,415,523	2,410,508	2,408,708	2,409,475	2,408,225	2,413,146	2,317,519	2,417,046	2,419,226	2,420,432	2,420,107	2,410,747	2,447,745
2024		2,322,008	2,322,311	2,325,499	2,307,982	2,321,113	2,321,815	2,322,496	2,323,145	2,321,159	2,238,727	2,320,219	2,334,558	2,326,880	2,333,881	2,322,758	2,365,527
2025		2,231,748	1,903,321	2,007,270	708,117	1,838,571	1,946,807	1,945,951	1,940,544	1,946,611	1,805,164	708,945	1,950,203	1,966,004	1,947,736	1,574,138	2,265,389
2026		1,921,582	1,675,431	1,726,816	964,263	710,120	1,843,485	1,715,344	1,705,541	1,712,928	1,613,718	713,634	1,845,453	1,713,675	1,714,831	1,555,776	1,959,946
2027		2,132,751	2,132,499	2,169,306	937,920	753,446	936,904	2,180,069	1,992,425	2,161,435	2,084,382	757,446	940,531	2,160,207	1,923,095	1,854,721	2,175,867
2028		2,351,859	1,882,784	1,957,853	839,957	837,919	841,063	1,963,910	1,334,152	1,935,654	1,908,331	843,033	846,004	1,929,543	1,440,878	1,169,084	2,243,975
2029		1,406,135	980,669	1,032,692	817,020	815,987	815,367	1,031,751	389,570	1,011,202	1,039,726	817,824	818,028	1,010,159	548,086	283,210	1,214,412
2030		1,291,948	884,027	941,350	754,307	753,917	752,967	942,478	384,987	925,215	944,577	755,104	755,092	920,791	485,496	236,062	1,166,328
2031		1,280,593	838,483	904,856	904,756	745,375	742,483	907,327	422,679	890,843	909,018	905,755	746,779	883,055	477,240	241,961	1,044,676
2032		1,061,748	708,939	773,030	769,831	631,695	630,830	772,860	353,071	757,829	777,038	768,332	632,634	750,207	442,294	219,613	860,084
2033		1,235,893	846,690	913,770	787,345	788,397	786,048	789,124	419,094	773,920	792,916	784,102	789,535	764,784	434,187	216,726	913,123
2034		1,315,485	980,208	1,073,259	943,262	944,835	942,407	697,349	312,199	858,580	888,278	938,753	945,955	878,728	637,705	224,800	994,477
2035		2,158,994	1,669,236	1,744,620	1,597,217	1,606,822	1,592,733	692,133	323,006	1,179,769	1,208,700	1,570,175	1,593,027	1,156,535	1,093,901	254,343	1,867,348
2036		2,359,227	1,902,369	1,970,549	1,837,381	1,824,306	1,828,123	689,344	342,275	1,146,889	1,199,081	1,798,924	1,814,874	1,168,254	1,248,231	284,485	2,061,137
2037		4,035,857	3,744,542	3,882,215	3,764,958	3,644,539	3,656,598	716,358	373,249	1,132,746	1,229,522	3,748,316	3,648,384	1,198,947	3,564,097	531,331	3,706,958
2038		5,243,885	5,101,818	5,147,391	5,055,231	4,837,627	4,942,298	689,545	371,585	1,568,822	1,647,698	4,954,437	4,854,776	1,930,041	4,206,560	902,898	4,945,233
2039		5,275,337	5,195,044	5,239,199	5,151,569	4,919,634	5,027,598	790,968	441,864	1,720,931	1,803,955	5,040,959	4,920,115	2,086,963	4,297,621	996,135	4,896,985
2040		5,006,853	4,976,101	4,996,107	5,045,435	4,779,808	4,941,195	541,647	258,477	1,182,904	1,209,627	4,898,523	4,695,041	1,393,819	4,048,660	878,873	4,803,458
2041		5,025,693	5,103,546	4,984,652	5,070,157	4,752,948	4,944,685	465,370	124,526	1,181,034	1,199,068	4,914,691	4,787,952	1,372,531	4,006,855	805,554	4,908,789
		76.2%	75.9%	76.4%	76.0%	77.5%	76.6%	97.8%	99.4%	94.4%	94.3%	76.7%	77.3%	93.5%	81.0%	96.2%	76.8%

Exhibit C-26: I&M CO2e Profile - Life-Cycle Emissions

I&M CO2 Profile - Life-Cycle Emissions - Expected (P50)

Portfolio	Historic Emissions	Preferred Portfolio	Reference Portfolio	Reference ' Portfolio	Rockport '24 Portfolio	Rockport '25 Portfolio	Rockport '26 Portfolio	Cook 2050+ Portfolio	Cook 2050+ and No Gas Portfolio	Rapid Technology Portfolio	Enhanced Regulation Portfolio	Rockport '24 NTG Portfolio	Rockport '26 NTG Portfolio	RTA NTG Portfolio	Expanded Build Limits Portfolio	Unlimited Renewable Portfolio	OVEC 2030 Portfolio
Type	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2	CO2
Unit	short tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons	tons
2005	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511	21,134,511
2006	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204	24,053,204
2007	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761	20,364,761
2008	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034	21,906,034
2009	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586	19,380,586
2010	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516	20,659,516
2011	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745	19,725,745
2012	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940	20,538,940
2013	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824	17,056,824
2014	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380	18,487,380
2015	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452	13,310,452
2016	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979	11,469,979
2017	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307	10,753,307
2018	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974	11,653,974
2019	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326	8,120,326
2020	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809	4,534,809
2021		3,689,955	3,682,985	3,680,440	3,684,394	3,683,166	3,687,085	3,685,654	3,687,128	3,685,530	3,682,067	3,684,533	3,688,340	3,686,513	3,708,394	3,687,706	3,689,946
2022		4,616,224	4,616,389	4,617,072	4,618,413	4,615,573	4,617,282	4,617,092	4,614,933	4,620,102	4,616,718	4,617,889	4,617,979	4,615,377	4,639,127	4,618,381	4,656,149
2023		2,333,940	2,318,584	2,335,137	2,335,749	2,331,177	2,329,516	2,330,239	2,329,160	2,333,480	2,247,400	2,337,705	2,339,745	2,340,797	2,340,284	2,331,458	2,367,698
2024		2,246,984	2,247,366	2,250,206	2,236,310	2,246,162	2,246,842	2,247,429	2,247,993	2,245,912	2,172,420	2,248,570	2,259,570	2,252,311	2,258,260	2,247,665	2,288,559
2025		2,210,291	1,979,842	2,034,052	889,196	1,923,419	2,021,044	2,020,232	2,014,804	2,020,429	1,892,028	895,916	2,024,496	2,027,557	2,022,678	1,997,886	2,242,871
2026		1,948,750	1,894,029	1,849,681	1,310,300	1,073,836	2,344,224	1,931,928	1,922,873	1,929,219	1,840,258	1,077,480	2,357,629	1,906,681	1,931,414	2,465,795	1,986,663
2027		2,243,589	2,365,027	2,403,476	1,325,471	1,114,319	1,536,995	2,412,981	2,198,646	2,394,417	2,327,977	1,118,350	1,541,172	2,393,458	2,270,949	2,751,426	2,286,123
2028		1,605,478	1,522,712	2,288,706	1,223,480	1,221,183	1,466,783	2,293,905	1,573,475	2,264,658	2,246,230	1,226,373	1,472,337	2,258,994	1,852,595	2,101,010	2,758,283
2029		1,756,660	1,384,445	1,443,518	1,197,041	1,195,924	1,443,387	1,442,200	707,245	1,418,964	1,451,397	1,197,681	1,446,044	1,417,993	1,037,068	1,288,944	1,820,518
2030		1,623,259	1,272,062	1,337,400	1,123,366	1,122,950	1,338,082	1,338,284	699,585	1,318,842	1,341,015	1,123,998	1,340,025	1,314,396	967,723	1,238,768	1,734,517
2031		1,597,097	1,214,361	1,290,030	1,289,402	1,107,189	1,291,598	1,292,247	737,156	1,273,696	1,294,570	1,290,279	1,296,151	1,265,845	955,924	1,244,603	1,551,196
2032		1,363,743	1,075,084	1,147,592	1,143,963	986,108	1,146,337	1,147,180	666,885	1,130,499	1,151,940	1,142,314	1,148,565	1,122,717	917,541	1,223,554	1,326,138
2033		1,543,513	1,219,487	1,295,525	1,150,951	1,151,988	1,293,942	1,152,817	727,577	1,135,911	1,157,339	1,147,470	1,297,736	1,126,713	902,022	1,213,479	1,355,343
2034		1,680,460	1,384,361	1,489,827	1,341,912	1,343,381	1,481,930	1,061,372	621,577	1,304,501	1,337,889	1,337,230	1,483,643	1,305,300	1,170,933	1,222,458	1,483,559
2035		2,549,272	2,070,552	2,157,450	1,991,510	2,012,758	2,132,433	1,044,099	622,882	1,649,156	1,681,791	1,964,101	2,130,079	1,625,760	1,638,222	1,242,974	2,390,395
2036		2,776,447	2,300,123	2,387,936	2,230,823	2,247,065	2,362,977	1,041,045	643,523	1,694,893	1,754,171	2,191,941	2,347,029	1,721,105	1,792,606	1,276,395	2,605,471
2037		5,347,449	5,026,518	5,193,508	5,053,844	4,973,848	5,057,939	1,067,604	675,066	1,794,368	1,903,661	5,035,173	5,046,339	1,876,051	4,997,868	1,555,807	5,128,328
2038		6,586,721	6,405,696	6,477,344	6,363,684	6,183,776	6,363,188	1,036,768	673,573	2,272,540	2,362,844	6,260,158	6,270,447	2,610,347	5,650,524	1,928,428	6,400,895
2039		6,654,828	6,507,062	6,577,455	6,467,333	6,271,216	6,467,704	1,147,477	748,745	2,442,283	2,536,789	6,353,535	6,353,627	2,786,464	5,746,163	2,029,557	6,392,894
2040		6,341,131	6,245,893	6,292,196	6,335,787	6,119,797	6,336,091	879,362	554,530	1,915,627	1,946,114	6,185,019	6,068,856	2,102,261	5,461,494	1,912,560	6,248,925
2041		6,371,141	6,385,295	6,288,643	6,358,211	6,097,355	6,357,560	802,255	410,937	1,936,381	1,957,049	6,198,506	6,191,119	2,102,824	5,408,561	1,835,356	6,393,242
		70%	70%	70%	70%	71%	70%	96%	98%	91%	91%	71%	71%	90%	74%	91%	70%

Exhibit D New Generation Resources

CAPITAL COST ASSUMPTIONS
Source: Siemens PTI, AEP I&M, NREL, IHS, EIA, EPA

Plant Parameters

Plant Parameters	Fossil				Storage	Nuclear	Renewables			
Technology	Advanced 1x1 w 90% CO2	Advanced 2x1 Combined Cycle	Advanced 1x1 Combined Cycle	Simple Cycle Frame CT	Batteries-Li-ion	Small Modular Reactor	Solar Tier-2	Solar+Storage	Solar Tier-1	Onshore Wind
Fuel	Nat.Gas	Nat. Gas.	Nat. Gas	Nat. Gas.	All	Ura.	Sun	Sun	Sun	Wind
Construction Time (Yrs)	7	6	5	5	1	10	1	1	1	1
Size (MW)	390	1,070	440	250	50MW/ 200MWh	600	50	100	50	200
Baseload Heat Rate, HHV (Btu/kWh)	6,431	6,370	6,431	9,905		10,046				
VOM (2019$/MWh)	5.84	1.87	2.55	0.60		3.03				PTC
FOM (2019$/kW-yr)	27.59	11.26	14.10	7.00	20.67	96.14	16.70	37.55	16.70	31.72
Book Life	30	30	30	30	30	40	35	10	35	30
Debt Life	30	30	30	30	10	40	35	10	35	30
Pre Tax WACC	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%	7.19%

All-in Capex, Avg. 2019$/kW	Adv. 1x1 CC w/90% CO2	Adv. 2x1 CC	Adv. 1x1 CC	Simple Frame CT	Batteries Li-ion	Small Modular Reactor	Solar Tier-2 Cost	Solar + Storage	Solar Tier-1 Cost	Onshore Wind
	2019$/kW	2019$/kW	2019$/kW	2019$/kW	2019$/kW	2019$/kW	2019 $/kW	2019 $/kW	2019 $/kW	2019 $/kW
2021	2,456	1,031	1,097	738	1,319	6,750	1,350	1,535	1,181	1,449
2022	2,419	1,020	1,085	735	1,232	6,715	1,296	1,454	1,134	1,421
2023	2,381	1,009	1,073	726	1,145	6,680	1,243	1,373	1,087	1,393
2024	2,326	995	1,059	713	1,058	6,645	1,189	1,293	1,040	1,363
2025	2,287	985	1,048	705	971	6,610	1,135	1,214	993	1,333
2026	2,260	979	1,042	699	935	6,575	1,147	1,232	1,003	1,301
2027	2,232	973	1,035	694	898	6,536	1,090	1,177	954	1,269
2028	2,210	969	1,030	690	862	6,500	1,033	1,121	904	1,236
2029	2,192	965	1,027	688	826	6,463	977	1,066	854	1,202
2030	2,171	961	1,022	684	790	6,418	920	1,011	804	1,168
2031	2,152	957	1,018	681	780	6,376	911	1,000	797	1,158
2032	2,133	953	1,014	678	770	6,331	903	990	790	1,149
2033	2,111	948	1,009	675	760	6,285	895	979	783	1,139
2034	2,093	945	1,005	672	751	6,247	887	968	776	1,130
2035	2,078	942	1,003	670	741	6,206	879	958	769	1,120
2036	2,060	939	999	668	731	6,157	871	947	762	1,111
2037	2,046	936	996	666	721	6,116	862	937	754	1,101
2038	2,031	934	993	664	711	6,074	854	926	747	1,091
2039	2,014	930	990	662	701	6,026	846	915	740	1,082
2040	1,997	927	986	660	691	5,978	838	905	733	1,072
2041	1,984	925	984	658	681	5,940	830	894	726	1,062

Exhibit E Energy Efficiency Bundles

Energy Efficiency (EE) IRP Bundles - MWh Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2023-2025 EE Vintage Bundles														
2023	59	510	6,341	19	42,904	945	21,452	690	64,571	6,647	4,499	1,928	13,180	1,604
2024	114	1,057	12,105	40	88,841	1,836	42,167	1,458	118,977	12,754	8,080	3,457	22,338	3,376
2025	166	1,631	17,126	62	134,599	2,663	60,904	2,343	167,285	18,662	11,193	4,737	27,231	5,332
2026	156	1,530	14,739	58	116,203	2,439	52,469		153,052	13,195	7,472	3,157	25,506	4,889
2027	146	1,428	12,155	54	96,198	2,196	43,324		137,682	7,859	3,733	1,571	23,781	4,410
2028	135	1,322	9,504	50	75,585	1,939	33,930		121,481	3,778	1,257	526	21,920	3,903
2029	123	1,209	6,938	46	55,529	1,675	24,821		104,809	1,100			19,957	3,379
2030	111	1,090	3,797	42	31,728	1,409	16,563		88,067				17,931	2,851
2031	99	971	2,340	37	13,084	1,149	9,691		71,693				15,904	2,332
2032	87	854	843	33		902	4,366		56,139				13,937	1,838
2033	75	740		28		674	1,322		41,859				12,015	1,381
2034	64	629		24		473			29,276				10,121	976
2035	52	518		20		305			18,758				8,227	634
2036	42	417		16		164			10,582				6,603	366
2037	33	328		13		70			4,893				5,184	173
2038	25	252		10		16			1,653				3,892	59
2039	18	176		7		3			307				1,875	9
2040	9	109		4									618	
2041	3	51		2										
2042		18		1										

Energy Efficiency (EE) IRP Bundles - MWh Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2026-2028 EE Vintage Bundles														
2026	59	691	6,566	28	60,336	982	24,885	3,338	55,702	13,670	8,640	3,212	4,572	2,534
2027	115	1,385	12,442	56	117,253	1,905	49,510	4,461	105,779	25,126	14,978	5,710	5,746	5,180
2028	167	2,076	17,511	84	169,066	2,759	73,644	5,465	151,091	33,825	19,233	7,375	6,076	7,857
2029	156	1,946	15,066	79	145,623	2,526	63,514		138,292	22,507	12,671	4,869	5,683	7,200
2030	146	1,817	12,420	74	120,215	2,274	52,516		124,461	11,331	6,140	2,372	5,288	6,489
2031	135	1,681	9,707	68	94,123	2,009	41,200		109,873	3,840	1,986	765	4,847	5,737
2032	123	1,537	7,082	63	54,903	1,735	30,209		94,852	211			4,391	4,962
2033	111	1,385	4,709	56	23,453	1,460	20,221		79,758				3,928	4,182
2034	99	1,233	2,379	50	60,336	1,190	10,515		64,985				3,466	3,416
2035	87	1,085	854	44	117,253	934	3,907		50,942				3,024	2,687
2036	75	939		38	169,066	698			38,036				2,588	2,015
2037	64	797		32	145,623	490			26,650				2,156	1,419
2038	52	655		27	120,215	315			17,118				1,724	919
2039	42	528		22	94,123	170			9,693				1,386	526
2040	33	415		17	54,903	72			4,508				1,078	246
2041	25	318		13	23,453	17			1,533				784	84
2042	18	221		9		3			285				239	13
2043	9	136		6									146	
2044	3	63		3									77	
2045		21		1									19	

Energy Efficiency (EE) IRP Bundles - MWh Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2029-2040 EE Vintage Bundles														
2029	59	803	6,623	34	68,775	1,012	30,906	6,413	49,113	19,728	11,223	4,005	6	3,277
2030	115	1,627	12,553	68	132,354	1,961	58,260	7,263	90,864	34,850	18,885	6,752	5	6,464
2031	167	2,417	17,658	101	188,839	2,835	84,490	7,991	127,490	44,922	23,404	8,531	5	9,474
2032	216	3,167	21,864	132	236,982	3,629	105,929	8,592	158,192	52,664	27,549	9,920	54	12,372
2033	261	3,983	25,135	167	276,155	4,337	125,187	9,065	183,813	54,678	27,596	9,918	301	15,454
2034	303	4,734	27,503	198	306,414	4,954	138,497	9,426	206,619	56,398	27,149	9,796	1,681	18,337
2035	340	5,420	29,071	227	311,778	5,478	149,360	9,697	229,012	59,661	28,414	10,211	7,056	21,075
2036	373	6,072	29,973	257	332,265	5,913	154,081	9,886	242,532	60,474	27,941	10,086	10,603	23,643
2037	402	6,657	30,021	283	335,883	6,260	152,340	10,015	259,298	60,154	27,206	9,908	12,340	26,031
2038	427	7,177	30,056	306	338,576	6,528	152,616	10,005	300,595	60,907	28,256	10,164	13,370	28,201
2039	449	7,629	30,065	326	340,485	6,722	154,245	9,988	331,319	60,168	27,702	10,059	12,026	30,070
2040	467	8,012	30,069	343	341,757	6,857	153,985	9,973	353,885	58,856	26,897	9,902	11,715	31,597
2041	421	7,252	23,373	311	263,701	5,867	119,536		306,707	34,847	15,960	5,899	10,175	28,354
2042	377	6,502	17,407	279	193,991	4,906	89,018		260,786	16,911	7,533	2,815	8,644	25,184
2043	333	5,764	12,278	248	133,973	4,015	62,722		217,192	5,509	2,377	893	7,160	22,105
2044	290	5,037	8,061	217	84,528	3,208	41,561		176,891				5,756	19,192
2045	248	4,323	4,781	186	46,034	2,494	24,718		140,447				4,454	16,416
2046	206	3,647	2,411	157	18,189	1,877	12,503		108,124				3,228	13,828
2047	169	3,012	865	130		1,357	4,430		80,138				1,985	11,245
2048	136	2,439		105		934	296		56,575				1,178	8,949
2050	107	1,932		84		579			37,370				710	6,919
2051	82	1,488		64		332			22,774				532	5,177
2052	60	1,108		48		161			12,295				335	3,716
2053	43	794		34		53			5,644				260	2,533
2054	29	548		24		18			1,900				210	1,619
2055	18	348		15		3			350				160	910
2056	9	195		8									111	369

Energy Efficiency (EE) IRP Bundles - MW Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2023-2025 EE Vintage Bundles														
2023	0.01	0.92	4.03	0.03	4.54	0.18	2.99	0	10.18	1.41	0.78	0.34	0.98	1.43
2024	0.01	1.9	7.68	0.07	9.65	0.34	5.9	0	18.72	2.61	1.39	0.6	1.66	3.01
2025	0.02	2.93	10.85	0.12	14.78	0.5	8.52	0	26.4	3.73	1.93	0.82	2.04	4.75
2026	0.02	2.75	9.34	0.11	12.76	0.45	7.34		24.15	2.62	1.29	0.55	1.91	4.35
2027	0.02	2.57	7.7	0.1	10.57	0.41	6.06		21.73	1.55	0.64	0.27	1.78	3.93
2028	0.02	2.38	6.02	0.09	8.32	0.36	4.75		19.17	0.74	0.22	0.09	1.64	3.48
2029	0.01	2.18	4.39	0.09	6.12	0.31	3.47		16.54	0.21			1.5	3.01
2030	0.01	1.96	2.4	0.08	3.52	0.26	2.32		13.9				1.34	2.54
2031	0.01	1.75	1.48	0.07	1.46	0.21	1.36		11.32				1.19	2.08
2032	0.01	1.54	0.53	0.06		0.17	0.61		8.86				1.04	1.64
2033	0.01	1.33		0.05		0.13	0.19		6.61				0.9	1.23
2034	0.01	1.13		0.04		0.09			4.62				0.76	0.87
2035	0.01	0.93		0.04		0.06			2.96				0.62	0.56
2036	0	0.75		0.03		0.03			1.67				0.5	0.33
2037	0	0.59		0.02		0.01			0.77				0.39	0.15
2038	0	0.45		0.02					0.26				0.29	0.05
2039	0	0.32		0.01					0.05				0.14	0.01
2040	0	0.2		0.01									0.05	
2041	0	0.09												
2042		0.03												

Energy Efficiency (EE) IRP Bundles - MW Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2026-2028 EE Vintage Bundles														
2026	0.01	1.25	4.15	0.05	6.74	0.18	3.47	0	8.89	2.77	1.49	0.55	0.35	2.24
2027	0.01	2.5	7.86	0.1	13.09	0.35	6.92	0	16.97	4.97	2.58	0.99	0.6	4.58
2028	0.02	3.75	11.07	0.16	18.86	0.5	10.27	0.01	24.3	6.59	3.31	1.28	0.68	6.94
2029	0.02	3.52	9.52	0.15	16.25	0.46	8.85		22.24	4.37	2.18	0.84	0.64	6.36
2030	0.02	3.28	7.85	0.14	13.41	0.42	7.32		20.02	2.18	1.06	0.41	0.6	5.73
2031	0.02	3.04	6.13	0.13	10.5	0.37	5.74		17.67	0.73	0.34	0.13	0.55	5.07
2032	0.01	2.78	4.48	0.12	6.12	0.32	4.21		15.26	0.04			0.5	4.38
2033	0.01	2.5	2.98	0.11	2.61	0.27	2.82		12.83				0.45	3.69
2034	0.01	2.23	1.5	0.09		0.22	1.46		10.46				0.4	3.02
2035	0	0	0	0		0.17	0.54		8.2				0.35	2.37
2036	0	0		0		0.13			6.12				0.3	1.78
2037	0	0		0		0.09			4.29				0.25	1.25
2038	0	0		0		0.06			2.76				0.2	0.81
2039	0	0		0		0.03			1.56				0.16	0.46
2040	0	0		0		0.01			0.73				0.13	0.22
2041	0	0		0		0			0.25				0.1	0.07
2042	0	0		0		0			0.05				0.04	0.01
2043	0	0		0									0.03	
2044	0	0											0.01	
2045		0											0.35	

Energy Efficiency (EE) IRP Bundles - MW Savings by Vintage

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2029-2040 EE Vintage Bundles														
2029	0.01	1.45	4.19	0.1	7.64	0.18	4.17	0.01	7.81	3.84	1.93	0.69	0	2.91
2030	0.01	2.94	7.94	0.1	14.68	0.35	7.87	0.01	14.53	6.68	3.24	1.17	0	5.77
2031	0.02	4.36	11.17	0.2	20.89	0.5	11.38	0.01	20.52	8.51	4.02	1.48	0	8.52
2032	0.03	5.72	13.83	0.2	26.14	0.64	14.25	0.01	25.6	9.99	4.73	1.72	0.01	11.2
2033	0.03	7.19	15.9	0.3	30.37	0.76	16.85	0.01	30.01	10.31	4.73	1.71	0.03	13.99
2034	0.04	8.56	17.4	0.4	33.66	0.86	18.63	0.01	33.94	10.55	4.66	1.69	0.05	16.65
2035	0.04	9.8	18.4	0.4	34.15	0.96	20.04	0.01	37.61	11.21	4.88	1.76	0.06	19.19
2036	0.04	10.98	18.97	0.5	36.3	1.03	20.7	0.01	39.8	11.32	4.8	1.74	0.05	21.59
2037	0.05	12.05	19.01	0.5	36.57	1.09	20.54	0.01	42.62	11.23	4.67	1.71	0.05	23.82
2038	0.05	12.99	19.04	0.6	36.74	1.13	20.55	0.01	49.21	11.44	4.85	1.75	0.07	25.85
2039	0.05	13.81	19.04	0.6	36.83	1.17	20.65	0.01	54.26	11.26	4.76	1.74	0.07	27.62
2040	0.05	14.51	19.05	0.6	36.86	1.19	20.53	0.01	58.05	10.97	4.62	1.71	0.26	29.12
2041	0.05	13.13	14.81	0.6	28.41	1.02	15.92		50.32	6.49	2.74	1.02	0.24	26.14
2042	0.04	11.77	11.03	0.5	20.87	0.85	11.84		42.79	3.14	1.29	0.49	0.22	23.22
2043	0.04	10.44	7.78	0.5	14.4	0.69	8.33		35.64	1.02	0.41	0.15	0.2	20.39
2044	0.03	9.12	5.11	0.4	9.08	0.55	5.51		29.02				0.18	17.7
2045	0.03	7.83	3.03	0.3	4.94	0.43	3.26		23.04				0.16	15.14
2046	0.02	6.61	1.53	0.3	1.95	0.32	1.64		17.73				0.14	12.75
2047	0.02	5.46	0.55	0.2		0.23	0.58		13.14				0.12	10.37
2048	0.02	4.42		0.2		0.16	0.04		9.28				0.11	8.25
2050	0.01	3.5		0.2		0.1			6.13				0.09	6.38
2051	0.01	2.7		0.1		0.06			3.74				0.08	4.78
2052	0.01	2.01		0.1		0.03			2.02				0.06	3.43
2053	0	1.44		0.1		0.01			0.93				0.05	2.34
2054	0	0.99		0		0			0.31				0.04	1.49
2055	0	0.63				0			0.06				0.03	0.84
2056	0	0.35											0.02	0.34

EE IRP Bundles - Bundle Costs (in $ '000s)

	Residential & IQW						Commercial & Industrial							
Year	R1	R2	R3	R4	R5	IQW	CI1	CI2	CI3	CI4	CI5	CI6	CI7	CI8
2023	$293.50	$652.20	$1,245.20	$49.30	$6,543.90	$1,254.10	$2,611.50	$107.20	$5,607.70	$1,138.20	$1,010.10	$406.50	$1,121.20	$81.20
2024	$293.80	$759.70	$1,349.90	$58.40	$6,724.30	$1,284.00	$2,764.70	$226.30	$5,215.60	$1,282.10	$1,053.40	$417.90	$844.50	$102.10
2025	$294.10	$855.90	$1,416.00	$66.60	$7,169.00	$1,314.50	$2,798.20	$363.80	$5,222.60	$1,531.10	$1,233.80	$472.60	$535.80	$128.40
2026	$294.40	$945.00	$1,464.40	$74.50	$7,597.30	$1,345.70	$2,850.60	$516.40	$5,163.20	$2,200.90	$1,904.70	$644.30	$397.20	$156.00
2027	$294.80	$1,023.90	$1,501.60	$81.70	$7,963.60	$1,377.50	$3,053.70	$680.40	$5,114.40	$2,343.10	$1,844.10	$663.00	$108.00	$183.30
2028	$295.20	$1,092.50	$1,530.30	$88.00	$8,314.20	$1,409.80	$3,421.20	$846.50	$5,168.80	$2,541.20	$1,900.20	$678.30	$51.80	$208.70
2029	$295.60	$1,148.90	$1,547.90	$93.40	$8,656.70	$1,442.80	$3,507.20	$992.10	$4,828.50	$3,092.70	$2,437.00	$800.30	$0.40	$230.50
2030	$296.00	$1,222.70	$1,574.20	$98.50	$9,037.70	$1,476.40	$3,464.40	$1,123.20	$4,506.20	$3,104.40	$2,233.20	$738.20	$0.00	$247.70
2031	$296.50	$1,259.60	$1,591.60	$102.20	$9,381.80	$1,510.60	$3,743.80	$1,235.80	$4,385.00	$3,174.00	$2,167.70	$757.10	$0.00	$234.80
2032	$296.90	$1,288.50	$1,607.80	$105.00	$9,714.00	$1,545.60	$3,734.20	$1,329.00	$4,183.90	$3,590.80	$2,620.20	$859.00	$2.30	$251.90
2033	$297.40	$1,486.10	$1,622.00	$117.90	$10,073.30	$1,581.30	$4,024.20	$1,402.60	$4,056.70	$3,570.80	$2,338.90	$787.40	$12.80	$293.50
2034	$297.70	$1,499.50	$1,636.70	$119.30	$10,447.30	$1,617.80	$3,908.60	$1,458.10	$4,158.00	$3,740.30	$2,255.60	$763.40	$114.50	$307.10
2035	$298.10	$1,510.90	$1,655.20	$120.40	$10,737.30	$1,655.40	$4,093.00	$1,497.90	$4,496.10	$4,104.60	$2,659.40	$876.80	$485.60	$325.30
2036	$298.30	$1,594.70	$1,673.70	$130.40	$11,013.30	$1,694.50	$3,866.30	$1,527.60	$4,008.70	$3,927.00	$2,396.70	$798.60	$363.90	$344.20
2037	$298.60	$1,602.80	$1,692.60	$130.70	$11,313.40	$1,733.40	$3,679.80	$1,547.10	$4,618.80	$3,770.00	$2,298.10	$774.80	$237.00	$362.40
2038	$298.90	$1,609.40	$1,709.30	$130.90	$11,542.30	$1,773.30	$4,031.40	$1,545.90	$7,220.10	$3,986.90	$2,642.20	$848.30	$200.30	$377.40
2039	$299.10	$1,614.70	$1,723.50	$131.00	$11,756.90	$1,814.00	$4,112.50	$1,544.00	$6,787.30	$3,823.10	$2,374.60	$806.80	$2.70	$383.80
2040	$300.80	$1,619.90	$1,743.30	$131.20	$11,966.90	$1,855.70	$4,063.40	$1,545.30	$6,532.40	$3,665.50	$2,264.60	$779.20	$89.90	$382.60

Exhibit F I&M Internal Hourly Load Data

Exhibit F

Indiana Michigan Power Company

Hourly Internal Load

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
1/1/2020	2,040	1,934	1,932	1,942	1,897	1,835	1,885	1,955
1/2/2020	2,031	2,017	2,014	2,026	2,077	2,162	2,287	2,422
1/3/2020	2,101	2,071	2,056	2,054	2,102	2,166	2,300	2,348
1/4/2020	2,022	1,976	1,938	1,896	1,927	1,975	2,010	2,077
1/5/2020	2,058	1,992	2,001	1,979	2,001	1,997	2,071	2,145
1/6/2020	2,111	2,114	2,072	2,131	2,186	2,306	2,489	2,601
1/7/2020	2,174	2,143	2,153	2,142	2,197	2,297	2,347	2,461
1/8/2020	2,066	2,088	2,130	2,099	2,195	2,419	2,621	2,719
1/9/2020	2,320	2,286	2,275	2,302	2,342	2,459	2,667	2,792
1/10/2020	2,216	2,161	2,101	1,996	2,018	2,160	2,313	2,410
1/11/2020	1,973	1,899	1,853	1,903	1,895	1,935	1,952	2,016
1/12/2020	2,046	1,997	1,961	1,938	1,933	1,919	1,938	2,052
1/13/2020	2,116	2,097	2,051	2,039	2,088	2,217	2,395	2,486
1/14/2020	2,166	2,163	2,086	2,145	2,196	2,294	2,471	2,575
1/15/2020	2,149	2,141	2,134	2,126	2,168	2,268	2,452	2,550
1/16/2020	2,156	2,146	2,119	2,117	2,171	2,285	2,411	2,602
1/17/2020	2,280	2,280	2,280	2,225	2,291	2,381	2,627	2,710
1/18/2020	2,251	2,228	2,204	2,162	2,311	2,311	2,345	2,372
1/19/2020	2,271	2,237	2,239	2,212	2,243	2,312	2,317	2,405
1/20/2020	2,431	2,411	2,414	2,436	2,472	2,578	2,719	2,756
1/21/2020	2,377	2,303	2,229	2,283	2,364	2,431	2,660	2,777
1/22/2020	2,345	2,300	2,317	2,293	2,358	2,471	2,550	2,649
1/23/2020	2,219	2,192	2,164	2,194	2,250	2,358	2,558	2,619
1/24/2020	2,290	2,239	2,231	2,220	2,216	2,329	2,452	2,571
1/25/2020	2,060	2,006	2,026	1,994	1,943	2,077	2,160	2,255
1/26/2020	2,114	2,073	2,052	2,039	2,029	2,035	2,083	2,139
1/27/2020	2,126	2,108	2,128	2,119	2,170	2,327	2,503	2,621
1/28/2020	2,201	2,139	2,152	2,157	2,207	2,265	2,335	2,532
1/29/2020	2,194	2,170	2,170	2,148	2,227	2,319	2,500	2,630
1/30/2020	2,217	2,195	2,166	2,213	2,235	2,383	2,589	2,694
1/31/2020	2,241	2,207	2,167	2,183	2,247	2,352	2,542	2,670

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
2/1/2020	2,133	2,093	2,071	2,057	2,087	2,109	2,155	2,244
2/2/2020	2,079	2,063	2,057	2,048	2,024	2,065	2,105	2,188
2/3/2020	1,935	1,931	1,954	1,977	2,065	2,102	2,353	2,517
2/4/2020	1,992	1,998	1,964	1,966	1,999	2,044	2,207	2,324
2/5/2020	2,171	2,162	2,158	2,168	2,219	2,326	2,539	2,653
2/6/2020	2,371	2,336	2,299	2,323	2,351	2,481	2,591	2,700
2/7/2020	2,346	2,367	2,376	2,361	2,371	2,496	2,630	2,734
2/8/2020	2,125	2,174	2,190	2,200	2,201	2,214	2,268	2,352
2/9/2020	2,045	2,001	2,030	2,032	2,000	2,038	2,104	2,147
2/10/2020	2,198	2,177	2,142	2,163	2,215	2,345	2,471	2,640
2/11/2020	2,199	2,170	2,164	2,167	2,186	2,286	2,479	2,571
2/12/2020	2,216	2,171	2,177	2,164	2,260	2,353	2,531	2,674
2/13/2020	2,253	2,153	2,194	2,258	2,355	2,426	2,541	2,614
2/14/2020	2,415	2,395	2,372	2,384	2,425	2,530	2,728	2,836
2/15/2020	2,388	2,350	2,313	2,308	2,368	2,376	2,452	2,483
2/16/2020	2,042	1,970	1,878	1,889	1,929	1,933	1,984	2,065
2/17/2020	2,135	2,145	2,146	2,142	2,182	2,323	2,528	2,613
2/18/2020	2,159	2,128	2,127	2,152	2,249	2,346	2,496	2,567
2/19/2020	2,197	2,206	2,184	2,197	2,198	2,318	2,411	2,488
2/20/2020	2,247	2,226	2,239	2,233	2,329	2,405	2,628	2,673
2/21/2020	2,375	2,342	2,337	2,315	2,407	2,518	2,697	2,821
2/22/2020	2,214	2,169	2,163	2,157	2,159	2,201	2,261	2,316
2/23/2020	2,045	2,038	1,970	1,995	1,983	1,999	2,019	2,132
2/24/2020	2,062	2,054	2,055	2,066	2,147	2,225	2,423	2,478
2/25/2020	2,263	2,224	2,163	2,192	2,226	2,361	2,497	2,647
2/26/2020	2,303	2,270	2,246	2,295	2,356	2,505	2,661	2,735
2/27/2020	2,288	2,263	2,240	2,262	2,320	2,415	2,552	2,729
2/28/2020	2,353	2,287	2,304	2,310	2,313	2,451	2,638	2,721
2/29/2020	2,223	2,208	2,178	2,183	2,166	2,235	2,288	2,320
3/1/2020	2,150	2,125	2,096	2,085	2,100	2,129	2,178	2,210
3/2/2020	2,043	2,005	2,022	2,057	2,114	2,222	2,356	2,519

Indiana Michigan Power Company
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(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
3/3/2020	2,068	2,055	2,034	2,008	2,085	2,193	2,233	2,347
3/4/2020	2,094	2,106	2,065	2,116	2,177	2,290	2,462	2,528
3/5/2020	2,144	2,159	2,174	2,195	2,244	2,392	2,570	2,652
3/6/2020	2,100	2,095	2,124	2,127	2,192	2,277	2,466	2,487
3/7/2020	2,047	2,046	2,013	2,067	2,094	2,154	2,201	2,175
3/8/2020	2,030	2,004	1,983	1,960	1,963	2,027	2,067	2,081
3/9/2020	1,974	1,968	1,971	2,030	2,138	2,301	2,411	2,414
3/10/2020	1,981	1,978	1,977	2,023	2,118	2,304	2,410	2,392
3/11/2020	2,063	2,073	2,099	2,169	2,255	2,462	2,573	2,562
3/12/2020	2,030	2,068	2,053	2,116	2,241	2,397	2,506	2,364
3/13/2020	2,025	2,012	2,028	2,053	2,134	2,296	2,370	2,400
3/14/2020	1,942	1,903	1,920	1,903	1,905	2,005	1,992	2,121
3/15/2020	1,973	1,910	1,945	1,887	1,914	1,937	2,051	2,089
3/16/2020	2,037	2,029	2,071	2,152	2,254	2,418	2,501	2,535
3/17/2020	2,062	2,067	2,046	2,138	2,210	2,384	2,464	2,488
3/18/2020	2,056	2,094	2,069	2,074	2,228	2,368	2,401	2,407
3/19/2020	1,979	1,995	2,077	2,112	2,144	2,276	2,398	2,426
3/20/2020	1,951	1,980	1,945	1,926	1,963	2,084	2,279	2,204
3/21/2020	1,948	1,909	1,936	1,925	1,977	2,017	2,083	2,093
3/22/2020	1,925	1,926	1,932	1,910	1,943	1,974	2,034	2,065
3/23/2020	2,025	2,028	2,023	2,063	2,105	2,284	2,392	2,388
3/24/2020	1,974	1,951	1,960	1,983	2,081	2,222	2,314	2,340
3/25/2020	1,951	1,981	1,992	1,977	2,070	2,209	2,290	2,310
3/26/2020	1,816	1,797	1,773	1,751	1,783	1,849	1,899	1,907
3/27/2020	1,715	1,723	1,715	1,777	1,865	1,967	2,096	2,134
3/28/2020	1,765	1,693	1,723	1,725	1,712	1,769	1,762	1,833
3/29/2020	1,704	1,700	1,654	1,665	1,674	1,709	1,693	1,773
3/30/2020	1,792	1,788	1,794	1,850	1,879	2,045	2,085	2,012
3/31/2020	1,866	1,855	1,841	1,907	1,980	2,119	2,152	2,178
4/1/2020	1,863	1,783	1,852	1,891	1,929	2,067	2,158	2,180
4/2/2020	1,911	1,873	1,861	1,914	1,979	2,086	2,115	2,143

Indiana Michigan Power Company
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(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
4/3/2020	1,725	1,732	1,750	1,767	1,790	1,910	1,990	1,967
4/4/2020	1,659	1,593	1,621	1,635	1,643	1,703	1,712	1,728
4/5/2020	1,609	1,615	1,629	1,629	1,574	1,679	1,742	1,748
4/6/2020	1,710	1,662	1,719	1,754	1,872	1,994	2,070	2,122
4/7/2020	1,710	1,731	1,680	1,760	1,741	1,900	1,958	1,998
4/8/2020	1,673	1,646	1,613	1,640	1,718	1,757	1,815	1,883
4/9/2020	1,680	1,646	1,655	1,677	1,709	1,897	1,963	2,038
4/10/2020	1,790	1,767	1,803	1,809	1,856	1,913	1,943	1,968
4/11/2020	1,731	1,693	1,718	1,733	1,727	1,741	1,784	1,817
4/12/2020	1,645	1,617	1,559	1,583	1,582	1,642	1,625	1,664
4/13/2020	1,597	1,563	1,581	1,627	1,691	1,842	1,929	1,993
4/14/2020	1,706	1,730	1,768	1,814	1,873	1,980	2,038	2,061
4/15/2020	1,772	1,733	1,711	1,735	1,786	1,902	1,963	1,980
4/16/2020	1,705	1,680	1,691	1,725	1,809	1,914	1,972	1,981
4/17/2020	1,675	1,649	1,680	1,747	1,814	1,909	1,996	2,067
4/18/2020	1,859	1,858	1,857	1,848	1,873	1,872	1,906	1,912
4/19/2020	1,699	1,710	1,691	1,710	1,739	1,713	1,741	1,752
4/20/2020	1,606	1,595	1,602	1,645	1,757	1,874	1,954	1,966
4/21/2020	1,596	1,571	1,580	1,631	1,734	1,832	1,893	1,948
4/22/2020	1,737	1,734	1,774	1,780	1,843	1,962	2,035	2,072
4/23/2020	1,697	1,624	1,637	1,679	1,747	1,873	1,915	1,941
4/24/2020	1,702	1,678	1,653	1,669	1,707	1,858	1,919	1,944
4/25/2020	1,568	1,556	1,555	1,596	1,599	1,690	1,728	1,755
4/26/2020	1,705	1,669	1,687	1,692	1,679	1,723	1,747	1,803
4/27/2020	1,701	1,680	1,683	1,781	1,874	1,986	2,028	2,094
4/28/2020	1,644	1,628	1,612	1,645	1,681	1,809	1,871	1,913
4/29/2020	1,656	1,549	1,598	1,649	1,720	1,808	1,896	1,921
4/30/2020	1,698	1,647	1,677	1,696	1,787	1,908	1,989	1,953
5/1/2020	1,704	1,705	1,728	1,731	1,786	1,848	1,963	2,016
5/2/2020	1,550	1,577	1,549	1,574	1,505	1,576	1,585	1,599
5/3/2020	1,561	1,554	1,551	1,497	1,470	1,492	1,464	1,544

Indiana Michigan Power Company
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(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
5/4/2020	1,532	1,521	1,541	1,588	1,697	1,814	1,915	1,973
5/5/2020	1,656	1,633	1,646	1,709	1,815	1,903	2,009	2,050
5/6/2020	1,722	1,620	1,566	1,616	1,697	1,797	1,840	1,893
5/7/2020	1,572	1,595	1,638	1,702	1,812	1,930	2,013	1,961
5/8/2020	1,634	1,618	1,653	1,700	1,752	1,784	1,949	1,933
5/9/2020	1,730	1,709	1,725	1,734	1,791	1,787	1,791	1,865
5/10/2020	1,609	1,633	1,636	1,643	1,659	1,644	1,670	1,686
5/11/2020	1,738	1,777	1,641	1,804	1,882	2,048	2,109	2,197
5/12/2020	1,868	1,863	1,855	1,875	1,971	2,100	2,197	2,208
5/13/2020	1,714	1,754	1,801	1,808	1,966	2,094	2,160	2,196
5/14/2020	1,760	1,715	1,692	1,767	1,865	1,948	2,046	2,108
5/15/2020	1,743	1,708	1,694	1,748	1,799	1,931	2,008	2,102
5/16/2020	1,627	1,617	1,612	1,571	1,617	1,670	1,642	1,697
5/17/2020	1,641	1,576	1,583	1,562	1,566	1,565	1,608	1,655
5/18/2020	1,761	1,738	1,713	1,783	1,836	1,960	2,035	2,103
5/19/2020	1,805	1,777	1,788	1,793	1,863	2,013	2,094	2,130
5/20/2020	1,617	1,580	1,543	1,573	1,670	1,800	1,937	2,083
5/21/2020	1,709	1,697	1,660	1,672	1,765	1,765	1,850	1,907
5/22/2020	1,668	1,660	1,674	1,695	1,775	1,888	1,957	2,047
5/23/2020	1,639	1,631	1,607	1,601	1,584	1,567	1,623	1,677
5/24/2020	1,631	1,600	1,545	1,490	1,527	1,522	1,575	1,652
5/25/2020	1,845	1,747	1,689	1,663	1,692	1,618	1,652	1,775
5/26/2020	1,934	1,856	1,862	1,868	1,948	2,071	2,185	2,211
5/27/2020	2,066	2,008	1,980	1,963	2,059	2,164	2,299	2,396
5/28/2020	1,979	1,969	1,953	1,966	2,054	2,147	2,255	2,341
5/29/2020	1,966	1,886	1,886	1,877	1,993	2,046	2,164	2,215
5/30/2020	1,678	1,657	1,614	1,594	1,627	1,629	1,669	1,727
5/31/2020	1,598	1,578	1,539	1,538	1,578	1,503	1,563	1,579
6/1/2020	1,635	1,645	1,643	1,698	1,784	1,862	2,028	2,063
6/2/2020	1,778	1,755	1,786	1,813	1,918	2,022	2,113	2,149
6/3/2020	2,081	1,978	1,813	1,810	1,851	1,920	2,010	2,093

Indiana Michigan Power Company
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DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
6/4/2020	1,944	1,939	1,920	1,902	1,876	2,031	2,186	2,199
6/5/2020	2,007	1,917	1,884	1,923	1,911	2,020	2,170	2,244
6/6/2020	1,958	1,869	1,814	1,792	1,799	1,728	1,835	2,008
6/7/2020	1,700	1,634	1,610	1,530	1,570	1,519	1,590	1,676
6/8/2020	1,801	1,741	1,673	1,735	1,837	1,935	1,977	2,072
6/9/2020	1,918	1,861	1,836	1,874	1,935	2,045	2,173	2,272
6/10/2020	2,180	2,142	2,114	2,127	2,223	2,360	2,489	2,568
6/11/2020	1,848	1,910	1,799	1,861	1,929	2,018	2,129	2,141
6/12/2020	1,819	1,750	1,659	1,775	1,837	1,864	1,973	2,123
6/13/2020	1,793	1,753	1,722	1,662	1,698	1,682	1,702	1,764
6/14/2020	1,628	1,576	1,574	1,565	1,596	1,572	1,587	1,643
6/15/2020	1,691	1,666	1,662	1,727	1,809	1,918	2,016	2,063
6/16/2020	1,841	1,816	1,787	1,843	1,922	2,028	2,112	2,139
6/17/2020	1,908	1,862	1,843	1,830	1,907	2,005	2,113	2,229
6/18/2020	1,949	1,870	1,852	1,876	1,922	1,904	2,003	2,088
6/19/2020	2,013	1,931	1,906	1,924	1,990	2,068	2,164	2,269
6/20/2020	1,979	1,904	1,867	1,833	1,819	1,615	1,714	1,934
6/21/2020	1,935	1,904	1,843	1,801	1,809	1,758	1,741	1,842
6/22/2020	1,859	1,805	1,803	1,841	1,920	2,025	2,170	2,293
6/23/2020	2,152	2,049	1,992	2,049	2,103	2,227	2,315	2,398
6/24/2020	1,891	1,857	1,876	1,907	1,978	2,059	2,170	2,208
6/25/2020	1,901	1,842	1,809	1,850	1,920	2,008	2,089	2,193
6/26/2020	1,888	1,875	1,822	1,846	1,890	2,042	2,126	2,226
6/27/2020	1,890	1,887	1,874	1,877	1,845	1,820	1,880	1,966
6/28/2020	1,883	1,821	1,769	1,772	1,740	1,748	1,760	1,906
6/29/2020	2,026	1,956	1,940	1,976	2,034	2,159	2,265	2,393
6/30/2020	2,202	2,145	2,087	2,060	2,110	2,221	2,303	2,377
7/1/2020	2,093	1,997	1,961	1,929	1,907	1,948	2,068	2,174
7/2/2020	2,032	1,984	1,931	1,933	1,982	2,036	2,111	2,255
7/3/2020	2,030	1,939	1,858	1,822	1,812	1,801	1,820	1,941
7/4/2020	2,069	1,897	1,883	1,838	1,799	1,784	1,818	1,913

Indiana Michigan Power Company
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DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
7/5/2020	1,949	1,849	1,818	1,796	1,747	1,727	1,751	1,837
7/6/2020	2,060	2,015	1,932	1,977	2,089	2,181	2,288	2,426
7/7/2020	2,247	2,183	2,135	2,112	2,211	2,211	2,343	2,518
7/8/2020	2,291	2,185	2,159	2,205	2,258	2,371	2,493	2,570
7/9/2020	2,219	2,153	2,099	2,087	2,148	2,197	2,336	2,444
7/10/2020	2,395	2,356	2,210	2,230	2,231	2,349	2,438	2,519
7/11/2020	1,973	1,883	1,921	1,872	1,931	1,941	1,984	2,117
7/12/2020	1,931	1,874	1,828	1,735	1,628	1,570	1,598	1,684
7/13/2020	1,947	1,909	1,849	1,881	1,983	2,040	2,133	2,245
7/14/2020	1,959	1,907	1,876	1,933	2,026	2,105	2,169	2,256
7/15/2020	2,090	2,003	1,969	1,967	2,088	2,146	2,253	2,353
7/16/2020	2,211	2,172	2,073	2,023	2,098	2,187	2,258	2,296
7/17/2020	2,004	1,956	1,909	1,929	2,026	2,135	2,160	2,279
7/18/2020	2,041	2,050	1,950	1,919	1,968	1,984	2,041	2,103
7/19/2020	2,321	2,242	2,191	2,082	2,138	2,164	2,169	2,301
7/20/2020	2,103	2,009	2,011	2,056	2,129	2,252	2,332	2,367
7/21/2020	2,087	2,061	2,001	2,002	2,100	2,213	2,265	2,347
7/22/2020	2,031	2,108	2,073	2,097	2,159	2,323	2,322	2,408
7/23/2020	2,135	2,095	2,074	2,101	2,209	2,316	2,364	2,472
7/24/2020	2,093	2,009	1,987	1,945	2,104	2,170	2,260	2,339
7/25/2020	2,029	1,980	1,925	1,867	1,843	1,931	1,939	2,081
7/26/2020	1,992	1,922	1,875	1,846	1,766	1,765	1,803	1,986
7/27/2020	2,375	2,311	2,286	2,295	2,384	2,463	2,599	2,689
7/28/2020	2,126	2,049	2,011	1,998	2,105	2,191	2,313	2,362
7/29/2020	2,135	2,109	2,100	2,051	2,102	2,255	2,359	2,381
7/30/2020	2,218	2,144	2,118	2,113	2,202	2,235	2,374	2,471
7/31/2020	2,074	2,042	2,036	2,051	2,118	2,179	2,220	2,324
8/1/2020	1,976	1,946	1,885	1,915	1,908	1,965	2,012	2,013
8/2/2020	1,923	1,857	1,807	1,801	1,773	1,801	1,762	1,828
8/3/2020	1,987	1,944	1,939	1,941	2,075	2,143	2,187	2,249
8/4/2020	2,001	1,952	1,946	1,956	2,049	2,166	2,208	2,265

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8/5/2020	1,849	1,816	1,802	1,769	1,824	1,849	1,887	1,949
8/6/2020	1,847	1,820	1,800	1,846	1,938	2,048	2,094	2,188
8/7/2020	1,926	1,896	1,879	1,907	1,960	2,052	2,076	2,173
8/8/2020	1,838	1,754	1,743	1,733	1,785	1,799	1,851	1,891
8/9/2020	1,881	1,861	1,781	1,747	1,721	1,749	1,769	1,880
8/10/2020	2,196	2,139	2,015	2,099	2,165	2,187	2,397	2,457
8/11/2020	2,021	1,991	1,954	2,033	2,096	2,207	2,287	2,350
8/12/2020	2,032	1,952	1,941	1,965	1,981	2,144	2,179	2,232
8/13/2020	2,070	1,975	1,984	1,974	1,986	2,101	2,158	2,209
8/14/2020	2,091	2,022	1,999	2,028	2,122	2,200	2,250	2,315
8/15/2020	1,988	1,923	1,867	1,865	1,854	1,896	1,880	2,041
8/16/2020	2,030	1,940	1,902	1,862	1,791	1,829	1,813	1,913
8/17/2020	1,971	1,929	1,924	1,965	2,042	2,185	2,160	2,311
8/18/2020	2,007	1,939	1,886	1,933	1,998	2,010	2,048	2,079
8/19/2020	1,830	1,764	1,719	1,720	1,900	2,017	2,074	2,125
8/20/2020	1,909	1,906	1,883	1,894	1,972	1,997	2,152	2,225
8/21/2020	1,954	1,923	1,892	1,876	1,991	2,102	2,118	2,217
8/22/2020	1,960	1,892	1,830	1,841	1,861	1,902	1,892	1,962
8/23/2020	1,924	1,868	1,851	1,801	1,790	1,786	1,744	1,863
8/24/2020	2,101	2,010	2,003	2,063	2,142	2,294	2,342	2,443
8/25/2020	2,353	2,277	2,196	2,166	2,311	2,470	2,535	2,632
8/26/2020	2,163	2,133	2,098	2,124	2,195	2,302	2,451	2,496
8/27/2020	2,300	2,268	2,193	2,163	2,330	2,455	2,566	2,632
8/28/2020	2,238	2,186	2,234	2,230	2,348	2,472	2,529	2,571
8/29/2020	2,087	2,061	1,976	1,982	2,011	2,059	2,073	2,138
8/30/2020	1,644	1,684	1,684	1,659	1,653	1,629	1,680	1,698
8/31/2020	1,834	1,832	1,866	1,910	2,006	2,133	2,206	2,216
9/1/2020	2,064	1,999	1,967	2,039	2,125	2,249	2,286	2,385
9/2/2020	2,109	2,094	2,063	2,073	2,090	2,178	2,255	2,280
9/3/2020	2,011	2,020	2,030	2,017	2,113	2,252	2,338	2,354
9/4/2020	1,944	1,876	1,867	1,891	1,992	2,088	2,123	2,133

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
9/5/2020	1,682	1,647	1,677	1,644	1,661	1,704	1,680	1,686
9/6/2020	1,689	1,637	1,641	1,579	1,601	1,637	1,607	1,648
9/7/2020	1,724	1,716	1,691	1,710	1,777	1,743	1,803	1,837
9/8/2020	1,869	1,837	1,861	1,910	2,001	2,150	2,245	2,260
9/9/2020	1,994	1,912	1,944	1,962	2,101	2,196	2,287	2,294
9/10/2020	2,064	2,005	1,967	2,005	2,094	2,233	2,300	2,244
9/11/2020	1,856	1,868	1,900	1,941	2,025	2,142	2,230	2,221
9/12/2020	1,798	1,797	1,776	1,772	1,781	1,823	1,895	1,938
9/13/2020	1,922	1,886	1,829	1,797	1,801	1,834	1,816	1,896
9/14/2020	1,752	1,764	1,756	1,845	1,881	2,058	2,161	2,136
9/15/2020	1,815	1,769	1,705	1,746	1,805	1,906	1,950	1,949
9/16/2020	1,783	1,743	1,777	1,818	1,893	2,051	2,123	2,131
9/17/2020	1,889	1,847	1,865	1,875	1,989	2,124	2,172	2,168
9/18/2020	1,803	1,775	1,772	1,790	1,861	2,004	2,103	2,087
9/19/2020	1,608	1,606	1,624	1,651	1,679	1,749	1,778	1,749
9/20/2020	1,604	1,516	1,561	1,566	1,602	1,630	1,659	1,687
9/21/2020	1,656	1,691	1,710	1,784	1,870	2,055	2,078	2,141
9/22/2020	1,754	1,726	1,717	1,710	1,903	2,023	2,055	2,142
9/23/2020	1,805	1,798	1,810	1,841	1,949	2,065	2,144	2,153
9/24/2020	1,872	1,846	1,844	1,873	1,951	2,095	2,165	2,159
9/25/2020	1,867	1,807	1,797	1,698	1,838	1,999	2,109	2,153
9/26/2020	1,755	1,751	1,738	1,772	1,800	1,843	1,829	1,886
9/27/2020	1,684	1,668	1,665	1,645	1,678	1,657	1,648	1,757
9/28/2020	1,809	1,822	1,857	1,798	1,916	2,087	2,162	2,259
9/29/2020	1,770	1,761	1,768	1,842	1,922	2,099	2,193	2,184
9/30/2020	1,839	1,794	1,781	1,822	1,940	2,033	2,123	2,174
10/1/2020	1,793	1,831	1,803	1,857	1,961	2,107	2,220	2,191
10/2/2020	1,710	1,712	1,793	1,849	1,929	2,094	2,209	2,176
10/3/2020	1,772	1,765	1,768	1,764	1,814	1,776	1,938	1,957
10/4/2020	1,653	1,579	1,603	1,590	1,617	1,664	1,734	1,782
10/5/2020	1,814	1,791	1,806	1,862	2,008	2,139	2,274	2,262

Indiana Michigan Power Company
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(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
10/6/2020	1,865	1,845	1,856	1,884	1,944	2,106	2,203	2,231
10/7/2020	1,823	1,761	1,814	1,851	1,985	2,096	2,202	2,214
10/8/2020	1,754	1,739	1,748	1,777	1,844	1,897	2,085	2,080
10/9/2020	1,700	1,749	1,764	1,822	1,857	1,984	2,160	2,152
10/10/2020	1,764	1,729	1,743	1,710	1,767	1,798	1,893	1,834
10/11/2020	1,703	1,681	1,640	1,585	1,602	1,674	1,711	1,682
10/12/2020	1,787	1,752	1,764	1,836	1,951	2,075	2,212	2,226
10/13/2020	1,820	1,780	1,806	1,855	1,978	2,075	2,225	2,209
10/14/2020	1,806	1,777	1,793	1,827	1,926	2,124	2,172	2,202
10/15/2020	1,836	1,760	1,791	1,832	1,932	2,046	2,177	2,196
10/16/2020	1,842	1,878	1,904	1,899	2,048	2,116	2,261	2,264
10/17/2020	1,775	1,706	1,766	1,812	1,873	1,917	1,974	1,982
10/18/2020	1,685	1,679	1,660	1,594	1,672	1,650	1,677	1,747
10/19/2020	1,664	1,643	1,657	1,718	1,782	1,930	2,046	2,078
10/20/2020	1,644	1,611	1,623	1,660	1,779	1,909	2,022	2,031
10/21/2020	1,650	1,610	1,625	1,657	1,751	1,848	1,952	1,966
10/22/2020	1,589	1,539	1,535	1,579	1,709	1,840	1,941	1,964
10/23/2020	1,664	1,644	1,646	1,724	1,845	1,960	2,029	2,074
10/24/2020	1,641	1,593	1,577	1,595	1,648	1,710	1,805	1,819
10/25/2020	1,752	1,710	1,721	1,727	1,731	1,732	1,823	1,821
10/26/2020	1,806	1,803	1,832	1,829	1,982	2,156	2,211	2,267
10/27/2020	1,923	1,891	1,898	1,924	2,052	2,166	2,285	2,315
10/28/2020	1,962	1,914	1,923	1,939	2,026	2,159	2,320	2,357
10/29/2020	1,959	1,990	1,993	2,037	2,191	2,314	2,418	2,354
10/30/2020	1,892	1,870	1,856	1,931	2,049	2,143	2,260	2,224
10/31/2020	1,900	1,904	1,913	1,894	1,957	1,949	2,036	2,077
11/1/2020	1,744	1,729	1,688	1,695	1,761	1,742	1,814	1,793
11/2/2020	1,937	1,955	1,941	1,944	2,011	2,149	2,240	2,386
11/3/2020	1,987	1,999	1,961	2,000	2,041	2,090	2,290	2,358
11/4/2020	1,930	1,910	1,879	1,897	1,927	2,052	2,192	2,304
11/5/2020	1,903	1,884	1,837	1,822	1,900	1,936	2,149	2,154

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(All Hours Are EST)

DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
11/6/2020	1,793	1,867	1,837	1,855	1,883	1,974	2,016	2,097
11/7/2020	1,763	1,710	1,759	1,748	1,756	1,810	1,831	1,830
11/8/2020	1,719	1,675	1,658	1,649	1,662	1,611	1,714	1,732
11/9/2020	1,772	1,766	1,714	1,741	1,781	1,931	2,097	2,191
11/10/2020	1,874	1,825	1,828	1,768	1,731	1,778	1,893	1,962
11/11/2020	1,774	1,744	1,747	1,740	1,766	1,816	1,979	2,076
11/12/2020	2,007	1,975	1,965	1,961	1,983	2,138	2,258	2,369
11/13/2020	1,913	1,963	1,949	1,969	2,015	2,065	2,248	2,298
11/14/2020	1,984	1,928	1,997	1,973	1,945	2,038	2,125	2,150
11/15/2020	1,841	1,797	1,813	1,833	1,770	1,796	1,883	1,815
11/16/2020	1,912	1,935	1,897	1,917	1,964	2,078	2,216	2,355
11/17/2020	1,988	1,927	1,903	1,923	2,018	2,095	2,222	2,348
11/18/2020	2,093	2,021	2,028	2,019	2,099	2,182	2,293	2,379
11/19/2020	2,050	2,007	2,015	2,018	2,043	2,118	2,287	2,369
11/20/2020	1,895	1,888	1,885	1,901	1,915	1,977	2,133	2,188
11/21/2020	1,777	1,779	1,771	1,775	1,816	1,877	1,925	1,973
11/22/2020	1,868	1,848	1,861	1,868	1,904	1,928	1,939	1,988
11/23/2020	1,953	1,920	1,889	1,904	1,926	2,065	2,211	2,313
11/24/2020	1,979	1,986	1,971	1,992	2,042	2,135	2,254	2,345
11/25/2020	1,876	1,861	1,934	1,975	2,014	2,086	2,193	2,336
11/26/2020	1,711	1,680	1,698	1,663	1,665	1,706	1,698	1,728
11/27/2020	1,541	1,669	1,610	1,632	1,641	1,665	1,746	1,825
11/28/2020	1,735	1,708	1,735	1,716	1,708	1,828	1,863	1,892
11/29/2020	1,811	1,827	1,829	1,833	1,762	1,744	1,897	1,945
11/30/2020	1,907	1,951	1,965	1,913	1,919	2,097	2,328	2,449
12/1/2020	2,169	2,106	2,050	2,090	2,116	2,201	2,408	2,442
12/2/2020	2,116	2,128	2,130	2,114	2,175	2,264	2,422	2,484
12/3/2020	2,116	2,110	2,104	2,115	2,142	2,222	2,276	2,366
12/4/2020	2,098	2,032	2,024	2,025	2,121	2,176	2,332	2,407
12/5/2020	1,968	1,948	1,971	1,982	1,982	2,085	2,143	2,222
12/6/2020	2,011	2,001	1,983	1,880	1,945	1,990	2,067	2,103

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DATE	HR1	HR2	HR3	HR4	HR5	HR6	HR7	HR8
12/7/2020	2,024	2,044	2,033	2,019	2,107	2,204	2,374	2,454
12/8/2020	2,181	2,144	2,124	2,091	2,167	2,244	2,353	2,513
12/9/2020	2,190	2,150	2,080	2,117	2,153	2,224	2,302	2,442
12/10/2020	2,052	2,079	2,002	2,057	2,137	2,196	2,348	2,458
12/11/2020	2,002	1,954	1,959	1,936	1,951	2,062	2,190	2,284
12/12/2020	1,958	1,942	1,915	1,887	1,887	1,921	2,001	1,995
12/13/2020	1,844	1,784	1,780	1,769	1,811	1,847	1,849	1,931
12/14/2020	1,995	1,938	1,981	1,975	2,033	2,166	2,301	2,397
12/15/2020	2,172	2,151	2,124	2,130	2,178	2,304	2,447	2,528
12/16/2020	2,159	2,150	2,177	2,211	2,287	2,401	2,398	2,526
12/17/2020	2,175	2,166	2,160	2,167	2,183	2,281	2,465	2,543
12/18/2020	2,148	2,096	2,045	2,094	2,127	2,273	2,405	2,500
12/19/2020	2,143	2,123	2,095	2,067	2,074	2,114	2,126	2,162
12/20/2020	1,914	1,953	1,944	1,872	1,922	1,918	1,943	2,017
12/21/2020	2,006	2,014	2,018	1,983	2,089	2,166	2,296	2,392
12/22/2020	2,098	2,051	2,007	1,936	2,024	2,159	2,287	2,418
12/23/2020	2,052	2,075	2,068	2,060	2,078	2,168	2,287	2,397
12/24/2020	1,880	1,819	1,802	1,780	1,804	1,860	1,926	2,015
12/25/2020	1,831	1,806	1,781	1,781	1,793	1,819	1,853	1,930
12/26/2020	1,916	1,871	1,845	1,821	1,827	1,840	1,889	1,970
12/27/2020	1,991	1,976	1,963	1,938	1,947	1,979	2,031	2,053
12/28/2020	1,887	1,886	1,873	1,894	1,924	2,047	2,125	2,182
12/29/2020	2,029	2,042	2,028	2,027	2,026	2,147	2,277	2,340
12/30/2020	2,068	2,013	2,005	1,990	2,038	2,086	2,158	2,205
12/31/2020	1,973	1,971	1,941	1,925	1,925	2,001	2,034	2,131

Indiana Michigan Power Company
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DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
1/1/2020	1,956	1,956	1,974	2,013	1,995	1,963	1,930	1,987
1/2/2020	2,415	2,458	2,434	2,357	2,363	2,309	2,290	2,321
1/3/2020	2,390	2,422	2,410	2,404	2,424	2,428	2,371	2,346
1/4/2020	2,100	2,154	2,198	2,229	2,197	2,225	2,176	2,197
1/5/2020	2,156	2,184	2,194	2,190	2,204	2,232	2,204	2,159
1/6/2020	2,577	2,539	2,574	2,493	2,476	2,479	2,428	2,349
1/7/2020	2,439	2,380	2,341	2,300	2,287	2,287	2,259	2,215
1/8/2020	2,709	2,688	2,666	2,640	2,535	2,626	2,549	2,509
1/9/2020	2,783	2,704	2,668	2,582	2,608	2,598	2,472	2,446
1/10/2020	2,417	2,402	2,372	2,425	2,449	2,467	2,387	2,325
1/11/2020	2,035	2,078	2,197	2,146	2,121	2,167	2,150	2,174
1/12/2020	2,096	2,060	2,139	2,147	2,186	2,140	2,114	2,183
1/13/2020	2,531	2,532	2,543	2,552	2,534	2,532	2,485	2,431
1/14/2020	2,568	2,550	2,557	2,551	2,523	2,492	2,463	2,405
1/15/2020	2,550	2,533	2,523	2,499	2,539	2,537	2,501	2,479
1/16/2020	2,596	2,650	2,646	2,611	2,589	2,553	2,485	2,485
1/17/2020	2,701	2,705	2,706	2,679	2,628	2,596	2,550	2,520
1/18/2020	2,400	2,406	2,458	2,437	2,422	2,382	2,369	2,320
1/19/2020	2,395	2,469	2,493	2,539	2,463	2,471	2,504	2,485
1/20/2020	2,824	2,823	2,786	2,740	2,721	2,684	2,627	2,605
1/21/2020	2,751	2,755	2,714	2,660	2,662	2,629	2,577	2,533
1/22/2020	2,595	2,546	2,530	2,482	2,463	2,426	2,375	2,324
1/23/2020	2,628	2,582	2,582	2,456	2,396	2,375	2,321	2,422
1/24/2020	2,635	2,604	2,552	2,544	2,559	2,529	2,454	2,413
1/25/2020	2,342	2,379	2,426	2,423	2,433	2,402	2,397	2,388
1/26/2020	2,189	2,230	2,243	2,248	2,283	2,265	2,223	2,215
1/27/2020	2,645	2,659	2,644	2,623	2,637	2,596	2,588	2,509
1/28/2020	2,597	2,572	2,607	2,573	2,560	2,557	2,534	2,463
1/29/2020	2,648	2,612	2,662	2,611	2,577	2,592	2,547	2,519
1/30/2020	2,680	2,659	2,639	2,615	2,612	2,598	2,564	2,523
1/31/2020	2,705	2,618	2,551	2,579	2,545	2,510	2,490	2,406

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(All Hours Are EST)

DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
2/1/2020	2,270	2,323	2,325	2,335	2,276	2,268	2,252	2,261
2/2/2020	2,190	2,193	2,165	2,156	2,122	2,088	1,996	2,026
2/3/2020	2,529	2,493	2,466	2,411	2,401	2,351	2,300	2,294
2/4/2020	2,293	2,305	2,348	2,351	2,385	2,395	2,368	2,339
2/5/2020	2,628	2,601	2,643	2,609	2,588	2,579	2,587	2,575
2/6/2020	2,723	2,739	2,722	2,723	2,739	2,751	2,749	2,677
2/7/2020	2,747	2,696	2,667	2,590	2,562	2,534	2,480	2,425
2/8/2020	2,376	2,265	2,343	2,267	2,241	2,218	2,215	2,234
2/9/2020	2,212	2,233	2,221	2,260	2,296	2,282	2,304	2,339
2/10/2020	2,641	2,653	2,669	2,619	2,624	2,596	2,519	2,508
2/11/2020	2,549	2,476	2,480	2,469	2,442	2,468	2,431	2,347
2/12/2020	2,611	2,627	2,634	2,620	2,612	2,609	2,587	2,559
2/13/2020	2,628	2,606	2,613	2,566	2,549	2,552	2,561	2,509
2/14/2020	2,812	2,743	2,758	2,719	2,679	2,637	2,548	2,515
2/15/2020	2,494	2,525	2,495	2,397	2,388	2,344	2,296	2,305
2/16/2020	2,112	2,143	2,089	2,056	2,050	2,046	2,025	2,038
2/17/2020	2,629	2,592	2,611	2,582	2,587	2,567	2,528	2,506
2/18/2020	2,575	2,596	2,583	2,540	2,516	2,505	2,476	2,461
2/19/2020	2,462	2,417	2,395	2,355	2,333	2,308	2,245	2,193
2/20/2020	2,675	2,660	2,662	2,638	2,633	2,602	2,524	2,552
2/21/2020	2,745	2,723	2,683	2,627	2,579	2,566	2,494	2,410
2/22/2020	2,340	2,306	2,261	2,213	2,177	2,140	2,107	2,075
2/23/2020	2,158	2,164	2,129	2,044	2,037	2,001	1,913	1,973
2/24/2020	2,559	2,594	2,582	2,532	2,536	2,473	2,464	2,410
2/25/2020	2,668	2,650	2,682	2,633	2,663	2,626	2,590	2,573
2/26/2020	2,764	2,775	2,745	2,713	2,686	2,656	2,565	2,497
2/27/2020	2,722	2,711	2,715	2,663	2,639	2,587	2,567	2,509
2/28/2020	2,708	2,677	2,646	2,581	2,568	2,562	2,458	2,424
2/29/2020	2,328	2,305	2,223	2,251	2,246	2,216	2,171	2,139
3/1/2020	2,202	2,183	2,133	2,114	2,094	2,060	2,026	2,040
3/2/2020	2,503	2,477	2,432	2,455	2,425	2,416	2,349	2,307

Indiana Michigan Power Company
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DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
3/3/2020	2,343	2,326	2,311	2,292	2,286	2,274	2,242	2,208
3/4/2020	2,545	2,409	2,384	2,390	2,448	2,381	2,366	2,310
3/5/2020	2,576	2,566	2,568	2,468	2,478	2,465	2,403	2,341
3/6/2020	2,432	2,502	2,561	2,555	2,541	2,472	2,458	2,365
3/7/2020	2,250	2,258	2,203	2,166	2,138	2,105	2,029	2,034
3/8/2020	2,098	2,070	2,079	2,083	2,053	2,022	2,006	1,990
3/9/2020	2,393	2,396	2,370	2,400	2,368	2,273	2,243	2,225
3/10/2020	2,446	2,423	2,440	2,433	2,401	2,373	2,336	2,318
3/11/2020	2,545	2,568	2,513	2,459	2,447	2,392	2,358	2,298
3/12/2020	2,415	2,439	2,372	2,350	2,343	2,309	2,268	2,264
3/13/2020	2,330	2,319	2,315	2,225	2,306	2,242	2,224	2,166
3/14/2020	2,190	2,243	2,280	2,228	2,258	2,249	2,203	2,179
3/15/2020	2,055	2,068	2,105	2,114	2,068	2,050	2,042	2,016
3/16/2020	2,562	2,569	2,550	2,510	2,521	2,370	2,404	2,361
3/17/2020	2,500	2,497	2,483	2,494	2,466	2,394	2,331	2,261
3/18/2020	2,429	2,448	2,455	2,562	2,574	2,577	2,547	2,507
3/19/2020	2,466	2,473	2,483	2,500	2,524	2,491	2,421	2,356
3/20/2020	2,296	2,313	2,285	2,341	2,212	2,274	2,231	2,260
3/21/2020	2,143	2,178	2,094	2,159	2,164	2,137	2,117	2,134
3/22/2020	2,120	2,074	2,125	2,085	2,059	2,051	2,116	2,176
3/23/2020	2,376	2,438	2,412	2,428	2,412	2,350	2,253	2,215
3/24/2020	2,392	2,364	2,290	2,252	2,307	2,328	2,284	2,237
3/25/2020	2,268	2,359	2,308	2,265	2,215	2,142	2,075	2,050
3/26/2020	1,911	1,910	1,906	1,912	1,892	1,862	1,870	1,851
3/27/2020	2,148	2,142	2,144	2,145	2,155	2,086	2,085	2,060
3/28/2020	1,892	1,919	1,928	1,931	1,910	1,862	1,907	1,918
3/29/2020	1,824	1,877	1,877	1,927	1,960	1,962	1,949	1,970
3/30/2020	2,047	2,062	2,134	2,179	2,195	2,205	2,151	2,140
3/31/2020	2,237	2,179	2,180	2,179	2,216	2,159	2,152	2,126
4/1/2020	2,203	2,190	2,173	2,189	2,198	2,134	2,064	2,076
4/2/2020	2,167	2,084	2,041	2,052	2,029	1,986	1,910	1,915

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DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
4/3/2020	2,019	1,997	1,967	1,966	1,890	1,852	1,835	1,819
4/4/2020	1,666	1,780	1,854	1,833	1,801	1,814	1,744	1,819
4/5/2020	1,785	1,800	1,862	1,812	1,810	1,751	1,754	1,735
4/6/2020	2,062	2,046	2,020	2,056	2,039	1,978	1,922	1,904
4/7/2020	1,952	2,006	1,928	1,907	1,994	1,997	1,970	1,911
4/8/2020	1,939	1,971	2,001	2,012	2,028	2,014	1,990	1,991
4/9/2020	2,067	2,086	2,126	2,034	2,088	2,062	2,051	2,050
4/10/2020	1,989	2,024	2,056	1,986	1,979	1,903	1,929	1,902
4/11/2020	1,877	1,847	1,821	1,845	1,767	1,786	1,720	1,717
4/12/2020	1,681	1,689	1,699	1,748	1,679	1,728	1,745	1,781
4/13/2020	2,043	2,096	2,137	2,162	2,117	2,082	2,026	1,975
4/14/2020	2,084	2,093	2,079	2,093	2,048	2,016	1,971	1,956
4/15/2020	2,030	2,044	2,053	2,057	2,033	1,988	1,933	1,902
4/16/2020	1,968	1,976	1,970	1,960	1,934	1,949	1,884	1,826
4/17/2020	2,131	2,189	2,186	2,168	2,161	2,122	2,081	2,064
4/18/2020	1,927	1,898	1,934	1,922	1,899	1,875	1,824	1,828
4/19/2020	1,799	1,809	1,814	1,807	1,759	1,738	1,697	1,717
4/20/2020	1,993	1,959	1,982	1,952	1,951	1,930	1,849	1,795
4/21/2020	1,970	2,044	2,054	2,043	2,046	1,982	1,939	1,899
4/22/2020	2,055	2,087	2,091	2,093	2,028	2,021	1,951	1,908
4/23/2020	1,990	2,009	2,059	2,060	2,043	1,953	1,915	1,895
4/24/2020	1,959	2,001	2,020	1,991	1,941	1,934	1,886	1,802
4/25/2020	1,799	1,808	1,834	1,845	1,810	1,804	1,799	1,835
4/26/2020	1,815	1,840	1,844	1,813	1,783	1,771	1,754	1,776
4/27/2020	2,090	2,005	2,078	2,072	2,057	1,991	1,952	1,913
4/28/2020	1,936	1,967	1,932	1,965	1,933	1,861	1,887	1,850
4/29/2020	2,026	2,107	2,110	2,059	2,064	2,031	1,995	1,962
4/30/2020	2,117	2,175	2,207	2,195	2,161	2,118	2,104	2,069
5/1/2020	2,026	2,025	1,971	1,936	1,936	1,856	1,780	1,753
5/2/2020	1,668	1,688	1,730	1,738	1,735	1,733	1,758	1,736
5/3/2020	1,615	1,589	1,625	1,686	1,697	1,740	1,718	1,746

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5/4/2020	2,027	2,015	2,026	2,028	2,019	1,953	1,923	1,891
5/5/2020	2,068	2,076	2,114	2,123	2,128	2,096	2,039	2,043
5/6/2020	1,887	1,892	1,891	1,883	1,852	1,810	1,749	1,717
5/7/2020	2,042	2,001	2,011	2,041	2,024	1,953	1,790	1,896
5/8/2020	2,090	2,144	2,120	2,116	2,099	2,042	1,988	1,936
5/9/2020	1,894	1,889	1,858	1,847	1,813	1,791	1,768	1,743
5/10/2020	1,784	1,784	1,706	1,812	1,714	1,700	1,680	1,770
5/11/2020	2,217	2,209	2,262	2,207	2,156	2,143	2,109	1,947
5/12/2020	2,217	2,201	2,196	2,151	2,126	2,043	1,984	1,962
5/13/2020	2,206	2,208	2,199	2,246	2,189	2,164	1,989	2,003
5/14/2020	2,134	2,113	2,159	2,180	2,170	2,170	2,108	2,071
5/15/2020	2,056	2,126	2,198	2,205	2,147	2,106	2,067	2,002
5/16/2020	1,725	1,739	1,776	1,768	1,795	1,791	1,821	1,861
5/17/2020	1,695	1,756	1,800	1,853	1,859	1,836	1,867	1,842
5/18/2020	2,207	2,259	2,272	2,283	2,218	2,222	2,183	2,137
5/19/2020	2,125	2,133	2,182	2,221	2,246	2,206	2,123	2,086
5/20/2020	2,140	2,161	2,185	2,165	2,116	2,077	2,065	2,006
5/21/2020	1,929	1,948	1,957	1,973	1,954	1,929	1,870	1,848
5/22/2020	2,061	2,101	2,119	2,108	2,097	2,074	2,036	1,947
5/23/2020	1,743	1,771	1,813	1,856	1,892	1,895	1,994	2,000
5/24/2020	1,815	1,863	1,956	2,013	2,103	2,148	2,209	2,207
5/25/2020	1,948	2,031	2,162	2,244	2,316	2,315	2,356	2,405
5/26/2020	2,415	2,581	2,695	2,839	2,890	2,925	2,968	2,863
5/27/2020	2,464	2,504	2,619	2,713	2,779	2,786	2,801	2,739
5/28/2020	2,405	2,450	2,474	2,493	2,462	2,433	2,429	2,467
5/29/2020	2,218	2,290	2,314	2,355	2,350	2,310	2,330	2,289
5/30/2020	1,793	1,867	1,839	1,910	1,937	1,941	1,895	1,926
5/31/2020	1,546	1,625	1,691	1,778	1,784	1,804	1,749	1,805
6/1/2020	2,136	2,202	2,219	2,230	2,264	2,213	2,154	2,092
6/2/2020	2,152	2,238	2,299	2,432	2,538	2,623	2,646	2,680
6/3/2020	2,187	2,305	2,359	2,410	2,435	2,432	2,406	2,403

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6/4/2020	2,322	2,458	2,479	2,564	2,666	2,694	2,660	2,694
6/5/2020	2,357	2,546	2,601	2,729	2,779	2,808	2,821	2,757
6/6/2020	2,121	2,200	2,145	2,239	2,290	2,300	2,365	2,384
6/7/2020	1,735	1,844	1,879	1,984	1,996	2,076	2,101	2,223
6/8/2020	2,271	2,303	2,335	2,439	2,562	2,622	2,625	2,670
6/9/2020	2,372	2,539	2,699	2,852	2,956	2,987	2,963	2,949
6/10/2020	2,676	2,774	2,889	3,012	3,035	2,950	2,805	2,705
6/11/2020	2,241	2,299	2,282	2,342	2,383	2,425	2,452	2,430
6/12/2020	2,119	2,290	2,326	2,403	2,421	2,456	2,446	2,460
6/13/2020	1,816	1,887	1,921	1,929	1,959	1,931	1,950	1,978
6/14/2020	1,686	1,741	1,791	1,772	1,850	1,856	1,865	1,911
6/15/2020	2,103	2,171	2,222	2,244	2,296	2,291	2,274	2,341
6/16/2020	2,223	2,310	2,410	2,473	2,525	2,558	2,582	2,596
6/17/2020	2,330	2,427	2,487	2,545	2,617	2,640	2,669	2,697
6/18/2020	2,149	2,232	2,343	2,439	2,515	2,573	2,609	2,629
6/19/2020	2,424	2,544	2,642	2,750	2,824	2,821	2,777	2,713
6/20/2020	2,083	2,260	2,363	2,469	2,598	2,628	2,660	2,636
6/21/2020	1,971	2,111	2,152	2,150	2,234	2,264	2,287	2,216
6/22/2020	2,414	2,491	2,632	2,728	2,805	2,839	2,791	2,803
6/23/2020	2,366	2,436	2,428	2,485	2,460	2,403	2,408	2,414
6/24/2020	2,224	2,360	2,355	2,445	2,508	2,532	2,440	2,497
6/25/2020	2,276	2,247	2,363	2,377	2,500	2,554	2,534	2,556
6/26/2020	2,329	2,420	2,454	2,550	2,575	2,556	2,535	2,476
6/27/2020	2,087	2,172	2,235	2,302	2,352	2,400	2,415	2,459
6/28/2020	2,011	2,091	2,211	2,338	2,408	2,482	2,547	2,570
6/29/2020	2,500	2,687	2,801	2,904	2,987	3,014	3,000	2,982
6/30/2020	2,474	2,618	2,697	2,781	2,892	2,917	2,940	2,926
7/1/2020	2,275	2,427	2,535	2,622	2,701	2,747	2,768	2,797
7/2/2020	2,414	2,532	2,703	2,788	2,792	2,886	2,897	2,923
7/3/2020	2,164	2,327	2,436	2,549	2,601	2,667	2,733	2,751
7/4/2020	2,149	2,314	2,466	2,579	2,684	2,715	2,624	2,613

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7/5/2020	1,968	2,104	2,380	2,478	2,556	2,617	2,706	2,624
7/6/2020	2,640	2,797	2,957	3,063	3,170	3,196	3,225	3,218
7/7/2020	2,666	2,848	3,035	3,169	3,226	3,240	3,224	3,204
7/8/2020	2,790	2,924	3,108	3,222	3,294	3,269	3,172	3,084
7/9/2020	2,682	2,897	3,040	3,163	3,230	3,270	3,318	3,236
7/10/2020	2,619	2,668	2,687	2,777	2,771	2,735	2,720	2,702
7/11/2020	2,177	2,357	2,460	2,399	2,517	2,595	2,593	2,626
7/12/2020	1,815	1,948	2,050	2,152	2,119	2,131	2,131	2,238
7/13/2020	2,285	2,468	2,505	2,603	2,630	2,698	2,683	2,695
7/14/2020	2,369	2,475	2,601	2,733	2,779	2,845	2,839	2,859
7/15/2020	2,515	2,674	2,716	2,907	2,978	3,079	3,051	2,999
7/16/2020	2,347	2,394	2,417	2,453	2,491	2,481	2,465	2,455
7/17/2020	2,352	2,496	2,587	2,693	2,781	2,840	2,866	2,882
7/18/2020	2,258	2,437	2,593	2,708	2,792	2,864	2,907	2,924
7/19/2020	2,372	2,525	2,513	2,551	2,637	2,579	2,501	2,449
7/20/2020	2,456	2,609	2,645	2,735	2,798	2,849	2,844	2,852
7/21/2020	2,449	2,562	2,661	2,784	2,941	2,919	2,867	2,764
7/22/2020	2,476	2,556	2,607	2,631	2,679	2,712	2,767	2,802
7/23/2020	2,604	2,678	2,802	2,887	2,938	2,922	2,986	2,976
7/24/2020	2,443	2,470	2,525	2,633	2,680	2,734	2,757	2,778
7/25/2020	2,181	2,304	2,484	2,568	2,622	2,646	2,664	2,736
7/26/2020	2,103	2,296	2,381	2,572	2,638	2,750	2,797	2,916
7/27/2020	2,859	2,941	3,007	3,101	3,103	3,069	3,039	2,973
7/28/2020	2,525	2,633	2,730	2,855	2,910	2,936	2,895	2,892
7/29/2020	2,578	2,741	2,780	2,904	3,004	3,017	3,035	3,073
7/30/2020	2,502	2,636	2,713	2,758	2,815	2,806	2,781	2,747
7/31/2020	2,388	2,478	2,518	2,615	2,611	2,668	2,718	2,706
8/1/2020	2,102	2,135	2,138	2,155	2,166	2,140	2,125	2,182
8/2/2020	1,843	1,904	1,890	1,979	2,046	2,120	2,189	2,229
8/3/2020	2,393	2,505	2,584	2,651	2,691	2,714	2,716	2,688
8/4/2020	2,234	2,335	2,372	2,394	2,411	2,458	2,412	2,384

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8/5/2020	1,984	2,061	2,105	2,130	2,167	2,186	2,173	2,176
8/6/2020	2,227	2,312	2,368	2,417	2,433	2,462	2,440	2,429
8/7/2020	2,231	2,329	2,345	2,375	2,427	2,448	2,497	2,551
8/8/2020	1,996	2,095	2,170	2,250	2,302	2,346	2,439	2,493
8/9/2020	2,063	2,225	2,346	2,475	2,582	2,624	2,713	2,750
8/10/2020	2,579	2,732	2,807	2,929	3,020	3,097	3,119	3,150
8/11/2020	2,406	2,501	2,546	2,636	2,773	2,813	2,854	2,839
8/12/2020	2,375	2,498	2,610	2,665	2,687	2,799	2,820	2,870
8/13/2020	2,415	2,534	2,607	2,694	2,777	2,826	2,899	2,922
8/14/2020	2,363	2,479	2,602	2,723	2,867	2,923	2,897	2,959
8/15/2020	2,160	2,292	2,406	2,520	2,609	2,664	2,705	2,698
8/16/2020	2,010	2,123	2,295	2,302	2,374	2,434	2,491	2,545
8/17/2020	2,418	2,539	2,595	2,601	2,755	2,767	2,730	2,708
8/18/2020	2,115	2,150	2,154	2,176	2,303	2,386	2,406	2,384
8/19/2020	2,133	2,199	2,222	2,338	2,469	2,478	2,525	2,505
8/20/2020	2,299	2,335	2,431	2,491	2,564	2,644	2,699	2,760
8/21/2020	2,260	2,409	2,529	2,611	2,702	2,758	2,769	2,797
8/22/2020	2,099	2,222	2,232	2,381	2,490	2,615	2,648	2,648
8/23/2020	1,983	2,117	2,290	2,388	2,482	2,535	2,638	2,682
8/24/2020	2,612	2,777	2,842	3,016	3,125	3,143	3,169	3,162
8/25/2020	2,693	2,804	2,879	2,966	3,017	3,045	3,062	3,056
8/26/2020	2,634	2,757	2,921	3,029	3,120	3,108	3,159	3,200
8/27/2020	2,755	2,865	3,011	3,115	3,176	3,167	3,090	3,106
8/28/2020	2,671	2,794	3,001	3,030	3,116	3,037	2,924	2,805
8/29/2020	2,215	2,311	2,370	2,402	2,415	2,440	2,455	2,436
8/30/2020	1,785	1,882	1,939	2,034	2,079	2,098	2,182	2,193
8/31/2020	2,259	2,412	2,459	2,536	2,609	2,671	2,681	2,730
9/1/2020	2,421	2,599	2,599	2,737	2,785	2,825	2,839	2,789
9/2/2020	2,295	2,344	2,377	2,419	2,481	2,506	2,503	2,483
9/3/2020	2,345	2,523	2,617	2,658	2,639	2,659	2,816	2,864
9/4/2020	2,221	2,250	2,267	2,329	2,420	2,394	2,430	2,388

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DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
9/5/2020	1,764	1,806	1,917	1,966	2,020	2,108	2,142	2,184
9/6/2020	1,710	1,801	1,837	1,898	1,845	1,914	1,956	1,998
9/7/2020	1,906	2,002	2,033	2,088	2,139	2,176	2,200	2,212
9/8/2020	2,318	2,405	2,442	2,638	2,667	2,708	2,708	2,701
9/9/2020	2,268	2,383	2,442	2,477	2,517	2,563	2,654	2,660
9/10/2020	2,331	2,397	2,418	2,428	2,417	2,381	2,385	2,354
9/11/2020	2,267	2,276	2,282	2,279	2,338	2,334	2,341	2,325
9/12/2020	1,919	2,020	2,067	2,129	2,205	2,234	2,305	2,288
9/13/2020	1,958	2,031	2,078	2,155	2,166	2,166	2,226	2,238
9/14/2020	2,171	2,264	2,214	2,275	2,262	2,318	2,251	2,298
9/15/2020	1,956	2,002	2,017	2,032	2,083	1,997	2,113	2,114
9/16/2020	2,178	2,209	2,181	2,241	2,278	2,290	2,300	2,341
9/17/2020	2,194	2,252	2,251	2,268	2,361	2,349	2,349	2,311
9/18/2020	2,154	2,134	2,135	2,130	2,137	2,125	2,108	2,089
9/19/2020	1,854	1,861	1,787	1,824	1,796	1,795	1,826	1,811
9/20/2020	1,717	1,729	1,716	1,799	1,801	1,797	1,809	1,819
9/21/2020	2,107	2,143	2,217	2,235	2,233	2,173	2,170	2,184
9/22/2020	2,173	2,188	2,236	2,283	2,257	2,253	2,282	2,260
9/23/2020	2,192	2,249	2,293	2,249	2,309	2,348	2,306	2,280
9/24/2020	2,166	2,229	2,279	2,317	2,350	2,381	2,392	2,351
9/25/2020	2,150	2,242	2,276	2,278	2,287	2,303	2,289	2,326
9/26/2020	1,905	1,977	1,993	2,026	2,072	2,095	2,129	2,148
9/27/2020	1,748	1,838	1,904	1,944	1,938	2,037	2,114	2,128
9/28/2020	2,198	2,251	2,263	2,272	2,328	2,235	2,147	2,150
9/29/2020	2,169	2,210	2,156	2,204	2,192	2,144	2,094	2,085
9/30/2020	2,168	2,179	2,236	2,264	2,251	2,215	2,175	2,172
10/1/2020	2,224	2,219	2,220	2,205	2,198	2,183	2,153	2,143
10/2/2020	2,232	2,227	2,215	2,194	2,181	2,106	2,065	1,981
10/3/2020	1,983	1,979	1,963	1,941	1,939	1,879	1,851	1,860
10/4/2020	1,836	1,876	1,902	1,929	1,931	1,897	1,922	1,911
10/5/2020	2,213	2,229	2,177	2,262	2,254	2,207	2,155	2,146

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
10/6/2020	2,197	2,182	2,208	2,225	2,201	2,193	2,159	2,134
10/7/2020	2,243	2,247	2,243	2,268	2,248	2,241	2,237	2,200
10/8/2020	1,981	2,002	2,011	2,024	2,027	2,002	1,965	1,961
10/9/2020	2,170	2,198	2,184	2,212	2,215	2,209	2,164	2,112
10/10/2020	1,968	1,944	1,917	1,998	1,945	1,947	1,967	2,018
10/11/2020	1,770	1,843	1,852	1,892	1,842	1,932	1,925	2,003
10/12/2020	2,241	2,302	2,272	2,310	2,278	2,301	2,197	2,282
10/13/2020	2,205	2,213	2,254	2,260	2,220	2,194	2,146	2,165
10/14/2020	2,247	2,223	2,240	2,233	2,196	2,147	2,137	2,117
10/15/2020	2,188	2,248	2,268	2,260	2,268	2,134	2,151	2,158
10/16/2020	2,301	2,277	2,196	2,165	2,165	2,111	2,081	2,040
10/17/2020	2,012	1,998	1,990	1,959	1,925	1,921	1,887	1,880
10/18/2020	1,743	1,784	1,782	1,761	1,741	1,748	1,777	1,826
10/19/2020	2,077	2,074	2,054	2,050	2,009	1,975	1,918	1,913
10/20/2020	2,041	2,045	2,029	2,021	2,002	1,985	1,952	1,943
10/21/2020	1,980	2,002	2,002	1,976	1,971	1,924	1,861	1,835
10/22/2020	1,958	1,969	1,979	1,983	2,006	1,996	1,983	1,969
10/23/2020	2,103	2,161	2,180	2,178	2,151	2,096	2,131	2,079
10/24/2020	1,842	1,788	1,840	1,889	1,862	1,873	1,848	1,873
10/25/2020	1,901	1,904	1,889	1,875	1,878	1,866	1,865	1,915
10/26/2020	2,264	2,297	2,319	2,292	2,266	2,270	2,250	2,198
10/27/2020	2,362	2,355	2,312	2,339	2,231	2,316	2,286	2,229
10/28/2020	2,358	2,275	2,263	2,286	2,215	2,254	2,158	2,138
10/29/2020	2,401	2,330	2,305	2,246	2,202	2,264	2,257	2,242
10/30/2020	2,243	2,280	2,235	2,224	2,217	2,118	2,088	2,098
10/31/2020	2,115	2,024	2,048	1,990	1,961	1,884	1,898	1,877
11/1/2020	1,886	1,967	2,007	2,065	2,078	2,089	2,096	2,083
11/2/2020	2,387	2,443	2,438	2,357	2,337	2,317	2,200	2,222
11/3/2020	2,366	2,339	2,330	2,268	2,273	2,262	2,192	2,111
11/4/2020	2,313	2,280	2,268	2,115	2,208	2,260	2,229	2,186
11/5/2020	2,207	2,225	2,260	2,242	2,275	2,245	2,177	2,113

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
11/6/2020	2,185	2,173	2,194	2,187	2,175	2,164	2,068	2,095
11/7/2020	1,900	1,896	1,908	1,879	1,938	1,788	1,714	1,698
11/8/2020	1,747	1,792	1,831	1,785	1,804	1,836	1,866	1,863
11/9/2020	2,164	2,206	2,245	2,138	2,104	2,145	2,174	2,098
11/10/2020	1,961	1,984	2,040	2,051	2,092	2,093	2,076	2,037
11/11/2020	2,109	2,149	2,129	2,142	2,168	2,117	2,135	2,098
11/12/2020	2,351	2,319	2,300	2,255	2,286	2,251	2,225	2,163
11/13/2020	2,307	2,312	2,244	2,250	2,293	2,258	2,163	2,144
11/14/2020	2,132	2,152	2,156	2,123	2,143	2,129	2,036	2,058
11/15/2020	1,889	1,938	1,854	1,794	1,818	1,900	1,900	1,914
11/16/2020	2,375	2,387	2,338	2,360	2,331	2,282	2,232	2,218
11/17/2020	2,365	2,402	2,395	2,340	2,340	2,333	2,277	2,224
11/18/2020	2,442	2,417	2,391	2,369	2,337	2,307	2,271	2,242
11/19/2020	2,285	2,291	2,285	2,268	2,282	2,124	2,160	2,052
11/20/2020	2,209	2,206	2,193	2,165	2,153	2,101	2,089	2,058
11/21/2020	2,011	2,070	2,067	2,046	2,014	2,048	1,929	1,993
11/22/2020	2,025	2,102	2,093	2,082	2,009	2,063	2,091	2,076
11/23/2020	2,310	2,302	2,296	2,254	2,260	2,274	2,201	2,154
11/24/2020	2,378	2,410	2,380	2,429	2,371	2,390	2,299	2,282
11/25/2020	2,358	2,348	2,399	2,371	2,306	2,253	2,250	2,231
11/26/2020	1,797	1,906	1,966	1,940	1,932	1,857	1,828	1,808
11/27/2020	1,860	1,877	1,920	1,920	1,885	1,875	1,873	1,861
11/28/2020	1,901	1,911	1,941	1,929	1,894	1,890	1,819	1,845
11/29/2020	1,914	1,925	1,913	1,900	1,891	1,878	1,842	1,907
11/30/2020	2,499	2,491	2,532	2,514	2,489	2,476	2,466	2,427
12/1/2020	2,501	2,518	2,474	2,463	2,507	2,503	2,467	2,377
12/2/2020	2,423	2,459	2,410	2,418	2,336	2,354	2,275	2,236
12/3/2020	2,347	2,299	2,304	2,246	2,225	2,199	2,163	2,117
12/4/2020	2,437	2,422	2,407	2,304	2,282	2,244	2,257	2,149
12/5/2020	2,181	2,182	2,208	2,211	2,207	2,201	2,178	2,120
12/6/2020	2,144	2,184	2,169	2,162	2,160	2,169	2,183	2,180

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR9	HR10	HR11	HR12	HR13	HR14	HR15	HR16
12/7/2020	2,495	2,532	2,526	2,500	2,506	2,486	2,429	2,387
12/8/2020	2,479	2,445	2,480	2,516	2,511	2,509	2,404	2,417
12/9/2020	2,460	2,432	2,387	2,334	2,349	2,309	2,290	2,199
12/10/2020	2,451	2,393	2,291	2,287	2,269	2,246	2,211	2,193
12/11/2020	2,303	2,324	2,308	2,270	2,268	2,238	2,197	2,151
12/12/2020	2,088	2,108	2,099	2,070	2,064	2,055	2,028	2,028
12/13/2020	1,997	1,892	2,037	2,035	2,087	2,051	2,085	2,069
12/14/2020	2,473	2,478	2,481	2,481	2,481	2,474	2,448	2,396
12/15/2020	2,521	2,549	2,510	2,384	2,445	2,433	2,431	2,404
12/16/2020	2,497	2,451	2,429	2,390	2,366	2,370	2,335	2,313
12/17/2020	2,534	2,550	2,541	2,544	2,540	2,532	2,480	2,405
12/18/2020	2,557	2,551	2,542	2,541	2,480	2,450	2,370	2,367
12/19/2020	2,216	2,242	2,228	2,199	2,154	2,133	2,177	2,154
12/20/2020	2,023	2,071	2,133	2,081	2,127	2,066	2,034	2,019
12/21/2020	2,444	2,464	2,468	2,471	2,484	2,471	2,411	2,257
12/22/2020	2,375	2,398	2,378	2,390	2,368	2,327	2,279	2,229
12/23/2020	2,380	2,359	2,365	2,374	2,351	2,308	2,266	2,193
12/24/2020	1,915	1,952	1,967	1,961	1,939	1,933	1,942	1,930
12/25/2020	1,975	2,017	2,014	2,001	1,995	1,965	1,941	1,940
12/26/2020	2,079	2,101	2,093	2,104	1,962	2,018	1,952	1,951
12/27/2020	2,070	2,009	2,073	2,048	2,075	2,031	1,962	1,894
12/28/2020	2,262	2,289	2,317	2,255	2,335	2,332	2,316	2,299
12/29/2020	2,338	2,374	2,325	2,298	2,257	2,251	2,285	2,276
12/30/2020	2,231	2,301	2,344	2,348	2,366	2,326	2,300	2,276
12/31/2020	2,139	2,150	2,173	2,134	2,116	2,077	2,063	2,052

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
1/1/2020	1,938	2,042	2,119	2,145	2,204	2,173	2,099	2,070
1/2/2020	2,308	2,389	2,395	2,363	2,356	2,263	2,173	2,153
1/3/2020	2,325	2,399	2,394	2,356	2,296	2,240	2,117	2,059
1/4/2020	2,216	2,260	2,289	2,268	2,254	2,202	2,149	2,068
1/5/2020	2,195	2,276	2,337	2,347	2,316	2,256	2,202	2,170
1/6/2020	2,361	2,397	2,505	2,478	2,424	2,370	2,280	2,187
1/7/2020	2,214	2,275	2,367	2,355	2,436	2,345	2,306	2,197
1/8/2020	2,524	2,490	2,592	2,614	2,558	2,548	2,460	2,385
1/9/2020	2,486	2,483	2,527	2,509	2,470	2,396	2,312	2,242
1/10/2020	2,328	2,365	2,298	2,304	2,311	2,260	2,201	2,038
1/11/2020	2,152	2,205	2,269	2,298	2,229	2,181	2,114	2,074
1/12/2020	2,196	2,289	2,340	2,330	2,319	2,280	2,216	2,149
1/13/2020	2,411	2,484	2,514	2,487	2,424	2,335	2,250	2,219
1/14/2020	2,388	2,357	2,462	2,427	2,419	2,388	2,324	2,235
1/15/2020	2,456	2,488	2,426	2,460	2,420	2,388	2,283	2,247
1/16/2020	2,512	2,597	2,646	2,601	2,592	2,560	2,443	2,339
1/17/2020	2,558	2,610	2,609	2,585	2,496	2,450	2,408	2,336
1/18/2020	2,362	2,399	2,464	2,449	2,423	2,415	2,368	2,310
1/19/2020	2,551	2,573	2,674	2,645	2,594	2,559	2,517	2,492
1/20/2020	2,600	2,659	2,713	2,708	2,648	2,595	2,477	2,431
1/21/2020	2,528	2,560	2,670	2,655	2,597	2,540	2,481	2,393
1/22/2020	2,315	2,357	2,468	2,448	2,435	2,445	2,362	2,270
1/23/2020	2,464	2,505	2,572	2,590	2,558	2,504	2,441	2,345
1/24/2020	2,440	2,410	2,439	2,367	2,368	2,322	2,213	2,084
1/25/2020	2,399	2,379	2,389	2,385	2,327	2,281	2,200	2,145
1/26/2020	2,258	2,275	2,339	2,293	2,265	2,263	2,223	2,117
1/27/2020	2,512	2,533	2,579	2,535	2,526	2,465	2,360	2,267
1/28/2020	2,483	2,515	2,557	2,568	2,528	2,486	2,362	2,281
1/29/2020	2,488	2,516	2,573	2,513	2,516	2,443	2,382	2,275
1/30/2020	2,499	2,456	2,518	2,574	2,531	2,479	2,383	2,293
1/31/2020	2,391	2,430	2,478	2,413	2,402	2,342	2,251	2,128

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
2/1/2020	2,248	2,306	2,355	2,308	2,306	2,266	2,224	2,160
2/2/2020	2,057	2,067	2,166	2,131	2,093	2,066	2,012	1,966
2/3/2020	2,268	2,285	2,362	2,368	2,329	2,252	2,154	2,029
2/4/2020	2,351	2,370	2,433	2,393	2,400	2,347	2,294	2,211
2/5/2020	2,611	2,680	2,761	2,682	2,670	2,634	2,542	2,481
2/6/2020	2,655	2,615	2,700	2,709	2,677	2,597	2,461	2,363
2/7/2020	2,402	2,410	2,482	2,475	2,446	2,408	2,306	2,080
2/8/2020	2,200	2,230	2,311	2,304	2,288	2,231	2,139	2,103
2/9/2020	2,375	2,362	2,444	2,450	2,422	2,353	2,277	2,250
2/10/2020	2,479	2,492	2,549	2,533	2,498	2,397	2,309	2,234
2/11/2020	2,402	2,405	2,490	2,493	2,489	2,438	2,342	2,293
2/12/2020	2,595	2,660	2,724	2,633	2,621	2,565	2,405	2,321
2/13/2020	2,489	2,541	2,642	2,683	2,649	2,626	2,497	2,452
2/14/2020	2,501	2,510	2,573	2,647	2,650	2,573	2,496	2,430
2/15/2020	2,315	2,331	2,383	2,344	2,297	2,237	2,172	2,106
2/16/2020	2,054	2,102	2,176	2,253	2,257	2,205	2,219	2,155
2/17/2020	2,511	2,544	2,604	2,572	2,536	2,475	2,383	2,247
2/18/2020	2,464	2,422	2,490	2,489	2,485	2,395	2,334	2,235
2/19/2020	2,173	2,193	2,292	2,392	2,458	2,412	2,333	2,184
2/20/2020	2,445	2,463	2,647	2,657	2,618	2,573	2,495	2,424
2/21/2020	2,391	2,374	2,448	2,494	2,486	2,439	2,329	2,270
2/22/2020	2,037	2,067	2,173	2,241	2,211	2,210	2,146	2,102
2/23/2020	1,972	1,977	2,065	2,139	2,182	2,144	2,098	1,976
2/24/2020	2,470	2,448	2,523	2,558	2,564	2,483	2,384	2,300
2/25/2020	2,608	2,601	2,653	2,652	2,623	2,539	2,444	2,317
2/26/2020	2,626	2,624	2,691	2,701	2,636	2,584	2,487	2,366
2/27/2020	2,501	2,494	2,553	2,603	2,576	2,477	2,449	2,344
2/28/2020	2,454	2,461	2,501	2,524	2,529	2,459	2,379	2,297
2/29/2020	2,143	2,157	2,214	2,307	2,297	2,284	2,237	2,157
3/1/2020	2,054	2,094	2,132	2,202	2,193	2,146	2,108	2,069
3/2/2020	2,267	2,276	2,317	2,354	2,319	2,225	2,121	2,095

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
3/3/2020	2,184	2,190	2,202	2,297	2,343	2,315	2,198	2,117
3/4/2020	2,278	2,304	2,308	2,396	2,403	2,309	2,280	2,162
3/5/2020	2,333	2,337	2,322	2,361	2,388	2,345	2,270	2,162
3/6/2020	2,448	2,459	2,415	2,424	2,409	2,336	2,243	2,138
3/7/2020	2,029	2,033	2,101	2,174	2,200	2,181	2,146	2,072
3/8/2020	1,964	2,018	2,059	2,184	2,194	2,088	2,034	1,985
3/9/2020	2,233	2,268	2,318	2,364	2,296	2,196	2,089	2,020
3/10/2020	2,315	2,287	2,344	2,423	2,395	2,299	2,209	2,127
3/11/2020	2,315	2,307	2,325	2,351	2,306	2,133	2,137	2,123
3/12/2020	2,241	2,254	2,222	2,322	2,298	2,231	2,082	2,041
3/13/2020	2,139	2,159	2,168	2,247	2,220	2,107	2,021	1,939
3/14/2020	2,233	2,181	2,215	2,298	2,250	2,136	2,054	2,009
3/15/2020	2,052	2,049	2,062	2,171	2,183	2,130	2,057	2,023
3/16/2020	2,274	2,276	2,293	2,287	2,204	2,098	2,079	2,085
3/17/2020	2,212	2,238	2,257	2,319	2,306	2,253	2,132	2,122
3/18/2020	2,481	2,385	2,324	2,388	2,336	2,225	2,115	1,988
3/19/2020	2,291	2,252	2,284	2,232	2,129	2,131	2,063	2,032
3/20/2020	2,181	2,177	2,216	2,227	2,176	2,112	1,970	1,936
3/21/2020	2,118	2,112	2,147	2,158	2,097	2,044	1,893	1,928
3/22/2020	2,157	2,180	2,222	2,192	2,157	2,108	2,074	2,081
3/23/2020	2,262	2,262	2,257	2,295	2,205	2,141	2,094	2,054
3/24/2020	2,164	2,227	2,230	2,246	2,225	2,141	1,984	1,970
3/25/2020	2,039	2,008	1,993	2,083	2,040	1,965	1,925	1,833
3/26/2020	1,877	1,960	1,922	1,986	1,942	1,896	1,822	1,678
3/27/2020	2,006	2,063	2,023	1,998	2,037	1,948	1,874	1,801
3/28/2020	1,920	1,939	1,959	1,950	1,892	1,889	1,787	1,733
3/29/2020	1,945	1,936	1,936	1,929	1,954	1,878	1,827	1,796
3/30/2020	2,128	2,117	2,083	2,115	2,092	1,991	1,923	1,867
3/31/2020	2,091	2,139	2,132	2,127	2,102	2,003	1,943	1,920
4/1/2020	2,051	2,074	2,012	2,056	2,054	1,996	1,918	1,868
4/2/2020	1,901	1,906	1,933	1,972	1,946	1,878	1,798	1,761

Indiana Michigan Power Company
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DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
4/3/2020	1,810	1,827	1,794	1,873	1,878	1,779	1,713	1,677
4/4/2020	1,846	1,871	1,829	1,899	1,873	1,775	1,673	1,607
4/5/2020	1,770	1,761	1,794	1,836	1,823	1,775	1,761	1,717
4/6/2020	1,898	1,928	1,895	1,986	1,857	1,815	1,735	1,763
4/7/2020	1,955	1,917	1,880	1,933	1,928	1,805	1,804	1,742
4/8/2020	1,991	2,000	2,004	2,025	2,005	1,906	1,806	1,733
4/9/2020	2,043	2,056	2,013	2,060	2,006	1,963	1,871	1,817
4/10/2020	1,854	1,841	1,847	1,918	1,883	1,854	1,744	1,737
4/11/2020	1,679	1,738	1,775	1,806	1,801	1,755	1,696	1,683
4/12/2020	1,748	1,781	1,779	1,822	1,810	1,765	1,644	1,586
4/13/2020	1,979	1,961	1,935	1,992	1,960	1,900	1,830	1,745
4/14/2020	1,967	1,940	1,926	1,953	1,993	1,906	1,877	1,813
4/15/2020	1,874	1,847	1,836	1,869	1,886	1,832	1,771	1,727
4/16/2020	1,823	1,828	1,846	1,814	1,861	1,827	1,760	1,727
4/17/2020	2,057	1,964	2,006	2,016	2,005	1,925	1,883	1,899
4/18/2020	1,811	1,816	1,844	1,872	1,881	1,840	1,793	1,757
4/19/2020	1,705	1,731	1,724	1,797	1,788	1,756	1,696	1,630
4/20/2020	1,819	1,826	1,804	1,819	1,825	1,789	1,647	1,668
4/21/2020	1,909	1,877	1,860	1,902	1,908	1,864	1,780	1,780
4/22/2020	1,871	1,894	1,910	1,923	1,907	1,829	1,775	1,690
4/23/2020	1,858	1,868	1,841	1,828	1,848	1,770	1,729	1,743
4/24/2020	1,836	1,781	1,684	1,765	1,717	1,656	1,627	1,640
4/25/2020	1,870	1,859	1,863	1,895	1,886	1,817	1,774	1,701
4/26/2020	1,742	1,773	1,747	1,781	1,735	1,749	1,656	1,606
4/27/2020	1,858	1,870	1,867	1,929	1,921	1,843	1,796	1,629
4/28/2020	1,845	1,850	1,843	1,867	1,879	1,809	1,752	1,770
4/29/2020	1,930	1,919	1,920	1,953	1,938	1,851	1,791	1,730
4/30/2020	2,029	2,011	1,994	1,951	1,960	1,914	1,790	1,791
5/1/2020	1,750	1,773	1,772	1,776	1,749	1,704	1,639	1,659
5/2/2020	1,816	1,855	1,830	1,769	1,830	1,758	1,669	1,595
5/3/2020	1,800	1,807	1,778	1,752	1,767	1,720	1,613	1,581

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DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
5/4/2020	1,912	1,904	1,845	1,839	1,897	1,851	1,758	1,693
5/5/2020	2,037	2,013	2,012	2,026	2,013	1,944	1,886	1,800
5/6/2020	1,699	1,687	1,680	1,700	1,736	1,674	1,597	1,546
5/7/2020	1,911	1,909	1,889	1,881	1,922	1,821	1,736	1,660
5/8/2020	1,882	1,909	1,863	1,913	1,960	1,894	1,813	1,784
5/9/2020	1,748	1,725	1,719	1,786	1,821	1,736	1,729	1,675
5/10/2020	1,815	1,810	1,840	1,882	1,910	1,846	1,828	1,698
5/11/2020	1,991	2,033	2,010	2,041	1,981	1,942	1,864	1,853
5/12/2020	1,878	1,888	1,903	1,912	1,971	1,906	1,879	1,808
5/13/2020	1,982	1,958	1,962	1,978	1,995	1,926	1,843	1,793
5/14/2020	2,035	2,010	1,971	1,978	1,991	1,933	1,861	1,806
5/15/2020	2,009	2,004	1,983	1,948	1,943	1,813	1,656	1,634
5/16/2020	1,914	1,924	1,917	1,878	1,895	1,868	1,785	1,700
5/17/2020	1,859	1,853	1,833	1,899	1,924	1,900	1,778	1,792
5/18/2020	2,094	2,075	2,050	2,035	2,047	2,008	1,887	1,813
5/19/2020	2,089	2,070	2,051	2,058	2,066	1,874	1,849	1,796
5/20/2020	1,986	1,938	1,932	1,960	1,986	1,909	1,814	1,774
5/21/2020	1,847	1,833	1,824	1,871	1,942	1,857	1,787	1,711
5/22/2020	1,968	1,976	1,956	1,910	1,932	1,853	1,748	1,689
5/23/2020	1,998	1,992	1,960	1,927	1,907	1,791	1,744	1,670
5/24/2020	2,276	2,319	2,307	2,241	2,195	2,145	2,042	1,958
5/25/2020	2,417	2,405	2,341	2,277	2,268	2,229	2,092	2,010
5/26/2020	2,821	2,884	2,785	2,689	2,629	2,482	2,256	2,183
5/27/2020	2,653	2,615	2,535	2,491	2,471	2,323	2,190	2,073
5/28/2020	2,447	2,447	2,401	2,313	2,275	2,198	2,084	2,024
5/29/2020	2,262	2,256	2,226	2,144	2,073	2,031	1,877	1,763
5/30/2020	1,923	1,918	1,895	1,859	1,876	1,781	1,738	1,674
5/31/2020	1,833	1,901	1,938	1,913	1,950	1,925	1,843	1,691
6/1/2020	2,113	2,134	2,094	2,081	2,034	1,962	1,879	1,847
6/2/2020	2,713	2,681	2,706	2,620	2,571	2,438	2,293	2,176
6/3/2020	2,409	2,451	2,368	2,312	2,264	2,177	2,028	1,987

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DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
6/4/2020	2,659	2,648	2,530	2,496	2,423	2,322	2,182	2,069
6/5/2020	2,773	2,724	2,664	2,567	2,460	2,312	2,142	2,061
6/6/2020	2,424	2,400	2,290	2,148	2,045	1,990	1,862	1,788
6/7/2020	2,227	2,298	2,260	2,248	2,158	2,086	1,965	1,823
6/8/2020	2,671	2,684	2,609	2,489	2,429	2,296	2,113	1,980
6/9/2020	2,855	2,801	2,730	2,620	2,518	2,481	2,372	2,256
6/10/2020	2,684	2,591	2,470	2,374	2,231	2,218	2,027	2,032
6/11/2020	2,473	2,469	2,375	2,321	2,281	2,143	1,975	1,905
6/12/2020	2,449	2,439	2,416	2,315	2,260	2,121	1,971	1,869
6/13/2020	2,012	1,993	1,945	1,895	1,851	1,815	1,729	1,631
6/14/2020	1,955	1,966	1,958	1,955	1,928	1,876	1,828	1,760
6/15/2020	2,338	2,303	2,302	2,261	2,202	2,120	2,021	1,929
6/16/2020	2,616	2,588	2,519	2,456	2,384	2,303	2,078	1,991
6/17/2020	2,683	2,672	2,596	2,516	2,454	2,345	2,166	2,056
6/18/2020	2,643	2,618	2,561	2,552	2,490	2,390	2,258	2,097
6/19/2020	2,740	2,767	2,696	2,624	2,534	2,390	2,215	2,081
6/20/2020	2,732	2,706	2,669	2,576	2,476	2,365	2,238	2,095
6/21/2020	2,200	2,187	2,152	2,169	2,172	2,048	1,958	1,932
6/22/2020	2,828	2,800	2,737	2,608	2,570	2,510	2,413	2,250
6/23/2020	2,418	2,349	2,294	2,293	2,190	2,120	2,018	1,934
6/24/2020	2,487	2,468	2,419	2,328	2,258	2,158	2,017	1,913
6/25/2020	2,555	2,585	2,513	2,380	2,297	2,290	2,059	2,004
6/26/2020	2,557	2,521	2,502	2,480	2,462	2,351	2,235	2,065
6/27/2020	2,437	2,420	2,391	2,355	2,309	2,194	2,068	1,952
6/28/2020	2,637	2,661	2,584	2,539	2,474	2,372	2,235	2,118
6/29/2020	2,989	2,921	2,849	2,782	2,704	2,607	2,422	2,271
6/30/2020	2,931	2,875	2,811	2,690	2,611	2,495	2,338	2,167
7/1/2020	2,829	2,807	2,767	2,646	2,547	2,465	2,271	2,150
7/2/2020	2,966	2,911	2,875	2,741	2,580	2,509	2,289	2,155
7/3/2020	2,809	2,773	2,716	2,618	2,524	2,443	2,286	2,166
7/4/2020	2,483	2,455	2,392	2,303	2,220	2,218	2,024	2,017

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DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
7/5/2020	2,748	2,795	2,771	2,692	2,595	2,501	2,346	2,171
7/6/2020	3,210	3,141	3,072	2,959	2,875	2,751	2,578	2,417
7/7/2020	3,101	3,066	3,015	2,923	2,810	2,646	2,502	2,401
7/8/2020	2,971	2,873	2,821	2,743	2,719	2,616	2,411	2,330
7/9/2020	3,258	3,269	3,167	3,063	2,945	2,769	2,686	2,522
7/10/2020	2,660	2,631	2,562	2,450	2,416	2,312	2,202	2,094
7/11/2020	2,634	2,580	2,529	2,414	2,353	2,244	2,136	2,029
7/12/2020	2,320	2,385	2,342	2,281	2,183	2,182	2,064	1,951
7/13/2020	2,709	2,696	2,621	2,547	2,426	2,328	2,192	2,084
7/14/2020	2,813	2,834	2,758	2,682	2,603	2,490	2,292	2,165
7/15/2020	3,008	2,924	2,804	2,737	2,666	2,601	2,424	2,325
7/16/2020	2,475	2,485	2,534	2,465	2,426	2,339	2,203	2,104
7/17/2020	2,798	2,826	2,811	2,659	2,528	2,457	2,272	2,061
7/18/2020	2,911	2,888	2,865	2,788	2,754	2,589	2,481	2,384
7/19/2020	2,378	2,425	2,334	2,351	2,236	2,262	2,150	2,142
7/20/2020	2,760	2,717	2,643	2,619	2,575	2,448	2,302	2,182
7/21/2020	2,658	2,648	2,590	2,530	2,536	2,447	2,330	2,231
7/22/2020	2,808	2,723	2,733	2,656	2,615	2,522	2,365	2,230
7/23/2020	2,932	2,915	2,810	2,735	2,647	2,514	2,386	2,238
7/24/2020	2,794	2,743	2,690	2,604	2,527	2,425	2,298	2,173
7/25/2020	2,774	2,709	2,708	2,583	2,455	2,411	2,183	2,110
7/26/2020	2,973	2,922	2,927	2,855	2,739	2,688	2,588	2,465
7/27/2020	2,834	2,747	2,694	2,619	2,511	2,456	2,317	2,232
7/28/2020	2,946	2,862	2,825	2,700	2,617	2,474	2,386	2,264
7/29/2020	3,036	3,066	2,921	2,829	2,777	2,629	2,452	2,309
7/30/2020	2,700	2,593	2,555	2,470	2,461	2,340	2,296	2,169
7/31/2020	2,698	2,640	2,508	2,474	2,386	2,294	2,146	2,060
8/1/2020	2,154	2,132	2,161	2,153	2,141	2,082	2,022	1,975
8/2/2020	2,325	2,335	2,300	2,281	2,157	2,144	2,004	1,997
8/3/2020	2,672	2,590	2,487	2,417	2,400	2,268	2,066	2,030
8/4/2020	2,370	2,354	2,278	2,226	2,207	2,101	1,987	1,884

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DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
8/5/2020	2,172	2,225	2,186	2,122	2,112	2,052	1,952	1,879
8/6/2020	2,421	2,374	2,374	2,313	2,259	2,185	2,048	1,979
8/7/2020	2,527	2,515	2,429	2,382	2,312	2,154	2,028	1,923
8/8/2020	2,519	2,517	2,481	2,378	2,316	2,167	2,063	1,949
8/9/2020	2,783	2,828	2,788	2,704	2,655	2,570	2,397	2,329
8/10/2020	3,098	3,036	2,871	2,651	2,554	2,388	2,241	2,134
8/11/2020	2,856	2,820	2,728	2,652	2,613	2,409	2,206	2,087
8/12/2020	2,909	2,833	2,812	2,660	2,512	2,443	2,276	2,118
8/13/2020	2,911	2,874	2,776	2,658	2,547	2,428	2,261	2,163
8/14/2020	2,909	2,823	2,725	2,616	2,498	2,371	2,234	2,061
8/15/2020	2,746	2,748	2,671	2,567	2,464	2,336	2,208	2,128
8/16/2020	2,594	2,595	2,511	2,356	2,319	2,228	2,129	2,025
8/17/2020	2,729	2,667	2,623	2,511	2,453	2,264	2,169	2,050
8/18/2020	2,365	2,399	2,331	2,311	2,213	2,153	2,028	1,893
8/19/2020	2,574	2,592	2,538	2,414	2,398	2,169	2,067	1,978
8/20/2020	2,753	2,741	2,676	2,567	2,482	2,303	2,150	2,029
8/21/2020	2,813	2,774	2,703	2,604	2,515	2,337	2,129	2,020
8/22/2020	2,717	2,663	2,611	2,519	2,377	2,257	2,148	2,045
8/23/2020	2,728	2,607	2,639	2,574	2,522	2,339	2,255	2,177
8/24/2020	3,147	3,134	3,050	2,951	2,838	2,675	2,510	2,378
8/25/2020	3,008	2,991	2,834	2,768	2,670	2,527	2,366	2,226
8/26/2020	3,158	3,081	3,001	2,893	2,684	2,629	2,513	2,389
8/27/2020	3,030	2,953	2,864	2,791	2,743	2,553	2,449	2,359
8/28/2020	2,717	2,682	2,667	2,601	2,583	2,396	2,276	2,162
8/29/2020	2,406	2,328	2,176	2,187	2,089	1,986	1,874	1,767
8/30/2020	2,218	2,242	2,176	2,199	2,156	2,088	1,889	1,905
8/31/2020	2,730	2,675	2,627	2,530	2,506	2,356	2,237	2,114
9/1/2020	2,741	2,636	2,614	2,590	2,528	2,381	2,274	2,108
9/2/2020	2,470	2,475	2,420	2,466	2,403	2,208	2,150	2,120
9/3/2020	2,765	2,728	2,613	2,538	2,498	2,333	2,144	2,037
9/4/2020	2,382	2,295	2,174	2,182	2,078	1,977	1,838	1,782

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9/5/2020	2,162	2,143	2,113	2,019	2,001	1,917	1,838	1,726
9/6/2020	2,072	2,044	2,029	2,047	2,028	1,931	1,874	1,789
9/7/2020	2,223	2,235	2,148	2,204	2,062	2,049	2,017	1,934
9/8/2020	2,571	2,531	2,555	2,510	2,432	2,268	2,136	2,082
9/9/2020	2,661	2,684	2,608	2,623	2,514	2,375	2,240	2,104
9/10/2020	2,264	2,279	2,243	2,288	2,214	2,171	2,035	1,939
9/11/2020	2,262	2,197	2,173	2,203	2,156	2,083	1,924	1,898
9/12/2020	2,331	2,346	2,327	2,293	2,242	2,142	2,021	1,988
9/13/2020	2,284	2,223	2,221	2,189	2,116	1,985	1,893	1,810
9/14/2020	2,269	2,223	2,188	2,221	2,164	2,017	1,917	1,786
9/15/2020	2,171	2,117	2,105	2,104	2,026	1,964	1,889	1,812
9/16/2020	2,296	2,278	2,232	2,268	2,185	2,093	1,977	1,881
9/17/2020	2,180	2,120	2,126	2,171	2,109	2,002	1,902	1,880
9/18/2020	2,042	2,009	1,981	2,037	1,967	1,897	1,794	1,697
9/19/2020	1,838	1,833	1,806	1,886	1,837	1,728	1,684	1,655
9/20/2020	1,876	1,904	1,893	1,944	1,921	1,787	1,717	1,740
9/21/2020	2,182	2,124	2,112	2,147	2,064	1,888	1,869	1,812
9/22/2020	2,243	2,226	2,215	2,208	2,095	2,014	1,936	1,858
9/23/2020	2,228	2,212	2,154	2,215	2,078	2,056	1,854	1,855
9/24/2020	2,341	2,324	2,269	2,277	2,191	2,088	1,967	1,908
9/25/2020	2,317	2,245	2,202	2,118	2,131	2,040	1,929	1,845
9/26/2020	2,117	2,097	2,065	1,990	1,950	1,926	1,838	1,727
9/27/2020	2,179	2,134	2,175	2,157	2,047	1,968	1,937	1,872
9/28/2020	2,130	2,110	2,098	2,102	2,086	1,961	1,816	1,757
9/29/2020	2,114	2,043	2,108	2,112	2,001	1,886	1,916	1,840
9/30/2020	2,126	2,051	2,105	2,159	2,019	1,989	1,903	1,831
10/1/2020	2,130	2,124	2,109	2,049	2,031	1,874	1,849	1,754
10/2/2020	1,915	1,923	2,075	2,090	2,035	1,949	1,919	1,799
10/3/2020	1,870	1,925	1,951	1,953	1,883	1,835	1,774	1,744
10/4/2020	1,887	1,907	1,965	1,995	1,901	1,855	1,811	1,846
10/5/2020	2,091	2,074	2,128	2,126	2,088	2,027	1,955	1,858

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
10/6/2020	2,136	2,107	2,130	2,111	2,073	2,004	1,928	1,865
10/7/2020	2,172	2,085	2,109	2,134	2,054	1,973	1,863	1,796
10/8/2020	1,952	1,977	1,993	2,026	1,924	1,808	1,808	1,692
10/9/2020	2,138	2,069	2,142	2,038	2,006	1,941	1,830	1,729
10/10/2020	1,995	1,983	2,029	1,998	1,957	1,916	1,831	1,769
10/11/2020	1,985	1,979	1,997	1,990	1,951	1,937	1,875	1,743
10/12/2020	2,267	2,237	2,183	2,104	2,083	1,907	1,927	1,725
10/13/2020	2,074	2,109	2,102	2,119	2,064	2,013	1,853	1,878
10/14/2020	2,144	2,122	2,145	2,162	2,088	1,988	1,934	1,888
10/15/2020	2,042	2,054	2,082	2,119	2,112	2,047	1,962	1,890
10/16/2020	2,034	2,012	2,073	2,009	1,976	1,924	1,810	1,815
10/17/2020	1,920	1,952	1,948	1,942	1,895	1,843	1,729	1,713
10/18/2020	1,843	1,865	1,904	1,897	1,856	1,818	1,783	1,720
10/19/2020	1,931	1,940	1,983	1,935	1,884	1,799	1,734	1,680
10/20/2020	1,903	1,861	1,985	1,978	1,904	1,827	1,732	1,682
10/21/2020	1,821	1,827	1,875	1,860	1,816	1,736	1,658	1,624
10/22/2020	1,969	1,949	2,022	1,999	1,919	1,837	1,756	1,717
10/23/2020	2,028	2,008	1,999	1,950	1,876	1,805	1,741	1,657
10/24/2020	1,883	1,874	1,835	1,905	1,857	1,875	1,830	1,759
10/25/2020	1,947	1,986	2,029	2,024	1,995	1,994	1,915	1,876
10/26/2020	2,217	2,173	2,293	2,275	2,180	2,110	2,023	1,925
10/27/2020	2,232	2,281	2,312	2,291	2,215	2,067	2,006	1,988
10/28/2020	2,126	2,189	2,236	2,172	2,132	2,036	1,997	1,951
10/29/2020	2,249	2,209	2,288	2,246	2,070	2,045	1,952	1,882
10/30/2020	2,057	2,095	2,134	2,157	2,050	1,986	1,981	1,935
10/31/2020	1,885	1,911	1,990	1,992	1,980	1,933	1,890	1,840
11/1/2020	2,136	2,172	2,175	2,167	2,171	2,112	2,015	1,998
11/2/2020	2,195	2,248	2,224	2,255	2,284	2,248	2,164	2,066
11/3/2020	2,124	2,162	2,259	2,207	2,159	2,117	2,026	1,994
11/4/2020	2,086	2,186	2,249	2,178	2,127	2,081	1,982	1,917
11/5/2020	2,142	2,132	2,131	2,150	2,080	2,028	1,855	1,798

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
11/6/2020	2,102	2,082	2,149	2,109	2,074	1,968	1,914	1,835
11/7/2020	1,694	1,747	1,769	1,747	1,855	1,821	1,822	1,745
11/8/2020	1,912	1,991	2,007	2,039	1,979	1,903	1,868	1,784
11/9/2020	2,070	2,137	2,198	2,176	2,131	2,051	1,983	1,921
11/10/2020	2,014	2,044	2,082	2,145	2,114	2,053	1,971	1,813
11/11/2020	2,076	2,148	2,178	2,175	2,191	2,111	2,066	1,989
11/12/2020	2,134	2,170	2,232	2,223	2,189	2,078	2,049	2,006
11/13/2020	2,147	2,212	2,253	2,173	2,219	2,158	2,110	2,036
11/14/2020	2,050	2,124	2,102	2,079	2,063	2,042	1,974	1,942
11/15/2020	1,999	2,053	2,090	2,118	2,071	2,040	2,026	1,918
11/16/2020	2,205	2,246	2,294	2,264	2,252	2,215	2,110	2,047
11/17/2020	2,254	2,235	2,341	2,327	2,324	2,230	2,147	2,097
11/18/2020	2,218	2,292	2,300	2,290	2,189	2,183	2,127	2,036
11/19/2020	2,133	2,184	2,181	2,158	2,134	2,075	1,985	1,946
11/20/2020	2,019	2,080	2,091	1,974	2,047	1,889	1,889	1,843
11/21/2020	2,011	2,040	2,110	2,089	2,057	2,012	1,963	1,890
11/22/2020	2,137	2,188	2,161	2,159	2,115	2,029	2,045	1,936
11/23/2020	2,172	2,223	2,283	2,220	2,209	2,151	2,062	2,011
11/24/2020	2,288	2,262	2,312	2,232	2,223	2,193	2,107	1,977
11/25/2020	2,185	2,268	2,209	2,205	2,127	2,091	1,974	1,824
11/26/2020	1,816	1,852	1,854	1,846	1,824	1,785	1,790	1,578
11/27/2020	1,927	1,968	1,971	1,938	1,934	1,913	1,801	1,773
11/28/2020	1,832	1,966	2,034	2,044	2,027	1,985	1,953	1,858
11/29/2020	1,947	2,065	2,068	2,106	2,022	2,051	1,945	1,946
11/30/2020	2,346	2,474	2,425	2,448	2,458	2,330	2,247	2,143
12/1/2020	2,429	2,529	2,524	2,515	2,410	2,372	2,298	2,170
12/2/2020	2,245	2,327	2,390	2,379	2,346	2,311	2,245	2,184
12/3/2020	2,106	2,192	2,228	2,259	2,252	2,197	2,171	2,153
12/4/2020	2,186	2,248	2,258	2,240	2,203	2,214	2,090	1,986
12/5/2020	2,179	2,261	2,294	2,256	2,201	2,142	2,149	2,056
12/6/2020	2,230	2,290	2,317	2,323	2,262	2,238	2,188	2,097

Indiana Michigan Power Company
2020 Hourly Load (MW)
(All Hours Are EST)

DATE	HR17	HR18	HR19	HR20	HR21	HR22	HR23	HR24
12/7/2020	2,389	2,388	2,455	2,444	2,410	2,364	2,279	2,199
12/8/2020	2,405	2,463	2,481	2,476	2,442	2,366	2,313	2,196
12/9/2020	2,210	2,300	2,335	2,328	2,305	2,258	2,155	2,101
12/10/2020	2,161	2,244	2,269	2,268	2,249	2,194	2,113	2,051
12/11/2020	2,130	2,190	2,179	2,155	2,149	2,100	2,082	2,024
12/12/2020	2,063	2,143	2,149	2,141	2,108	2,093	1,976	1,937
12/13/2020	2,109	2,198	2,193	2,186	2,130	2,117	2,056	2,056
12/14/2020	2,371	2,451	2,450	2,470	2,421	2,381	2,311	2,220
12/15/2020	2,345	2,462	2,465	2,480	2,465	2,361	2,242	2,252
12/16/2020	2,316	2,426	2,495	2,484	2,486	2,402	2,255	2,218
12/17/2020	2,451	2,465	2,446	2,457	2,443	2,385	2,308	2,237
12/18/2020	2,395	2,442	2,433	2,379	2,400	2,360	2,288	2,188
12/19/2020	2,176	2,226	2,231	2,179	2,166	2,105	2,003	2,006
12/20/2020	2,043	2,127	2,204	2,225	2,215	2,162	2,135	2,105
12/21/2020	2,365	2,383	2,422	2,389	2,374	2,321	2,242	2,178
12/22/2020	2,248	2,320	2,342	2,320	2,331	2,281	2,229	2,170
12/23/2020	2,203	2,231	2,237	2,203	2,160	2,091	2,036	1,968
12/24/2020	1,956	2,015	2,027	2,015	1,987	1,971	1,925	1,878
12/25/2020	1,940	2,012	2,051	2,068	2,050	2,048	2,006	1,964
12/26/2020	2,018	2,124	2,163	2,148	2,156	2,126	2,095	2,028
12/27/2020	1,902	2,085	2,135	2,122	2,114	2,059	1,989	1,936
12/28/2020	2,291	2,327	2,371	2,328	2,309	2,228	2,189	2,030
12/29/2020	2,214	2,316	2,369	2,362	2,318	2,265	2,206	2,146
12/30/2020	2,283	2,284	2,315	2,293	2,238	2,214	2,068	2,046
12/31/2020	1,991	2,063	2,148	2,074	2,097	2,084	2,024	1,999

Exhibit G Stakeholder Process Exhibits

Communication and documentation of the Company's Stakeholder interactions can be found on the Company's IRP website at the following address:

https://www.indianamichiganpower.com/community/projects/irp/

Additionally, a copy of each presentation, minutes and IRP questions and responses can also be found in IRP Appendix Volume 4. This includes:

Stakeholder Website Comments
Stakeholder Meeting 1 Minutes and Presentation
Stakeholder Meeting 2 Minutes and Presentation
Stakeholder Meeting 3a Minutes and Presentation
Stakeholder Meeting 3b Minutes and Presentation
Stakeholder Meeting 4 Minutes and Presentation
Indiana Michigan Power All-Source Informational RFP Stakeholder Review Meeting
AURORA Technical Conference Agenda

Exhibit H Cross Reference Table

Cross Reference Table 170 IAC 4-7	Report Reference
170 IAC 4-7-2 Integrated resource plan submission	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:	
(1) The IRP.	
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following:	
(A) The utility's energy and demand forecasts and input data used to develop the forecasts.	Vol1, Exhibit A
(B) The characteristics and costs per unit of resources examined in the IRP.	Vol1, Exhibit D
(C) Input and output files from capacity planning models, in electronic format.	Vol1, Vol 2, Vol3
(D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file.	Vol1, Exhibit C
If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	n/a
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following:	Vol 1, Exhibit B, Public Summary Document
(A) A brief description of the utility's:	
(i) existing resources;	
(ii) preferred resource portfolio;	
(iii) key factors influencing the preferred resource portfolio;	
(iv) short term action plan;	
(v) public advisory process; and	
(vi) additional details requested by the director.	
(B) A simplified discussion of the utility's resource types and load characteristics. The utility shall make the IRP summary readily accessible on its website.	
(d) Contemporaneously with the submission of an IRP under this section, a utility shall provide to the director the following information:	Transmittal Letter
(1) The name and address of known individuals or entities considered by the utility to be interested parties.	

(2) A statement that the utility has sent known interested parties, electronically or by deposit in the United States mail, first class postage prepaid, a notice of the utility's submission of the IRP to the commission. The notice must include the following information:	
(A) A general description of the subject matter of the submitted IRP.	
(B) A statement that the commission invites interested parties to submit written comments on the utility's IRP within ninety (90) days of the IRP submittal. An interested party includes a business, organization, or particular customer that participated in the utility's previous public advisory process or submitted comments on the utility's previous IRP. A utility is not required to separately notify other customers.	
(3) A statement that the utility served a copy of the documents submitted under subsection (c) on the OUCC.	
170 4-7-2.6 Public Advisory Process	
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within fifteen (15) business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within fifteen (15) business days or the agreed time frame, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	Stakeholder Feedback section 4
(c) The utility shall solicit, consider, and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.	
(d) The utility retains full responsibility for the content of its IRP.	
(e) The utility shall conduct a public advisory process as follows:	
(1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:	
(A) An introduction to the IRP and public advisory process.	
(B) The utility's load forecast.	
(C) Evaluation of existing resources.	
(D) Evaluation of supply-side and demand-side resource alternatives, including:	
(i) associated costs;	
(ii) quantifiable benefits; and	
(iii) performance attributes.	
(E) Modeling methods.	
(F) Modeling inputs.	
(G) Treatment of risk and uncertainty.	
(H) Discussion seeking input on its candidate resource portfolios.	
(I) The utility's scenarios and sensitivities.	
(J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	
(2) The utility may hold additional meetings.	

(3) The schedule for meetings shall: (A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	
(4) The utility or its designee shall: (A) chair the participation process; (B) schedule meetings; (C) develop and publish to its website agendas and relevant material for those meetings at least seven (7) calendar days prior to the eeting; and (D) develop and publish to its website meeting minutes within fifteen (15) calendar days following the meeting.	
(5) Interested parties may request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	
(6) The utility shall take reasonable steps to notify: (A) its customers; (B) the commission; (C) interested parties; and (D) the OUCC; of its public advisory process.	
170 IAC 4-7-4 Integrated resource plan contents	
An IRP must include the following:	
(1) At least a twenty (20) year future period for predicted or forecasted analyses.	Section 9
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	Section 5
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	Section 5
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	Section 6
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	Section 7.6
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	Section 7.6
(7) The resource screening analysis and resource summary table required by section 7 of this rule.	Section 7.6, Appendix D
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	Section 8
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	Section 9
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	Section 10
(11) A discussion of the:	Section 7.1
(A) inputs;	
(B) methods; and	
(C) definitions; used by the utility in the IRP.	

(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If the IRP references a third-party data source, the IRP must include for the relevant data:	Appendix Exhibits
(A) source title;	
(B) author;	
(C) publishing address;	
(D) date;	
(E) page number; and	
(F) an explanation of adjustments made to the data.	
The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by:	Section 5
(A) customer class;	
(B) rate class;	
(C) NAICS code;	
(D) DSM program; and	
(E) end-use.	
(14) The database in subdivision (13) may be developed using, but not limited to, the following methods:	
(A) Load research developed by the individual utility.	
(B) Load research developed in conjunction with another utility.	
(C) Load research developed by another utility and modified to meet the characteristics of that utility.	
(D) Engineering estimates.	
(E) Load data developed by a non-utility source.	
(15) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on:	
(A) end-use penetration;	
(B) end-use saturation rates; and	
(C) end-use electricity consumption patterns.	
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs, and other aspects of planning.	
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e) of this rule.	
(18) A discussion of distributed generation within the service territory and its potential effects on:	Section 5.11
(A) generation planning;	
(B) transmission planning;	
(C) distribution planning; and	
(D) load forecasting.	
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	Section 7.1

(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	Section 6.4.2
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	Section 6.5
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Section 8
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	Section 6.5
(24) A discussion of how the utilities' resource planning objectives, such as:	Section 9
(A) cost effectiveness;	
(B) rate impacts;	
(C) risks; and	
(D) uncertainty; were balanced in selecting its preferred resource portfolio.	
(25) A description and analysis of the utility's base case scenario, sometimes referred to as a business as usual case or reference case. The base case scenario is the most likely future scenario and must meet the following criteria:	Section 8
(A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections, and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs.	Section 8
(B) Include:	
(i) existing federal environmental laws;	
(ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and	
(iii) existing policies, such as tax incentives for renewable resources.	
(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable.	
(D) Not include future resources, laws, or policies unless:	
(i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received;	
(ii) future resources have obtained the necessary regulatory approvals; and	
(iii) future laws and policies have a high probability of being enacted. A base case scenario need not align with the utility's preferred resource portfolio.	
(26) A description and analysis of alternative scenarios to the base case scenario, including comparison of the alternative scenarios to the base case scenario.	Section 8

(27) A brief description of the models, focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715:	Section 6.7.8
(A) The most current power flow data models, studies, and sensitivity analysis.	
(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC).	
(C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following:	
(i) The limits of the utility's transmission use.	
(ii) The utility's assessment practices developed through experience and study.	
(iii) Operating restrictions and limitations particular to the utility.	
(28) A list and description of the methods used by the utility in developing the IRP, including the following:	Section 7.1
(A) For models used in the IRP, the model's structure and reasoning for its use.	
(B) The utility's effort to develop and improve the methodology and inputs, including for its:	Section 5.13
(i) load forecast;	
(ii) forecasted impact from demand-side programs;	
(iii) cost estimates; and	
(iv) analysis of risk and uncertainty.	
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following:	Section 7.5
(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.	
(B) The avoided transmission capacity cost.	
(C) The avoided distribution capacity cost.	
(D) The avoided operating cost, including:	
(i) fuel cost;	
(ii) plant operation and maintenance costs;	
(iii) spinning reserve;	
(iv) emission allowances;	
(v) environmental compliance costs; and	
(vi) transmission and distribution operation and maintenance costs.	

(30) A summary of the utility's most recent public advisory process, including the following:	Section 4, Appendix Volume 4
(A) Key issues discussed.	
(B) How the utility responded to the issues.	
(C) A description of how stakeholder input was used in developing the IRP.	
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	Section 7
170 IAC 4-7-5 Energy and demand forecasts	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following:	Section 5
(1) Historical load shapes, including the following:	
(A) Annual load shapes.	
(B) Seasonal load shapes.	
(C) Monthly load shapes.	
(D) Selected weekly load shapes.	
(E) Selected daily load shapes, which shall include summer and winter peak days, and a typical weekday and weekend day.	
(2) Disaggregation of historical data and forecasts by:	
(A) customer class;	
(B) interruptible load; and	
(C) end-use; where information permits.	
(3) Actual and weather normalized energy and demand levels.	
(4) A discussion of methods and processes used to weather normalize.	
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following:	
(A) Total system.	
(B) Customer classes or rate classes, or both.	
(C) Firm wholesale power sales.	
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	
(8) Justification for the selected forecasting methodology.	
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools, and analysis.	
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including:	Section 5
(1) high;	
(2) low; and	
(3) most probable; peak demand and energy use forecasts.	

(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as:	Section 5
(1) Rate of change in population.	
(2) Economic activity.	
(3) Fuel prices.	
(4) Price elasticity.	
(5) Penetration of new technology.	
(6) Demographic changes in population.	
(7) Customer usage.	
(8) Changes in technology.	
(9) Behavioral factors affecting customer consumption.	
(10) State and federal energy policies.	
(11) State and federal environmental policies.	
170 IAC 4-7-6 Description of available resources	
(a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated:	
(1) The net and gross dependable generating capacity of the system and each generating unit.	Section 6.4
(2) The expected changes to existing generating capacity, including the following:	
(A) Retirements.	
(B) Deratings.	
(C) Plant life extensions.	
(D) Repowering.	
(E) Refurbishment.	
(3) A fuel price forecast by generating unit.	Appendix Vol 3, Exhibit B
(4) The significant environmental effects, including:	Section 6.5
(A) air emissions;	
(B) solid waste disposal;	
(C) hazardous waste;	
(D) subsequent disposal; and	
(E) water consumption and discharge; at existing fossil fueled generating units.	
(5) An analysis of the existing utility transmission system that includes the following:	Section 6.7
(A) An evaluation of the adequacy to support load growth and expected power transfers.	
(B) An evaluation of the supply-side resource potential of actions to reduce:	
(i) transmission losses;	

(ii) congestion; and	
(iii) energy costs.	
(C) An evaluation of the potential impact of demand-side resources on the transmission network.	Section 6.6.1
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy.	Section 6.6.2
The information listed in subdivisions (1) through (4) and in subdivision (6) shall be provided for each year of the future planning period.	
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:	
(1) Rate design as a resource in meeting future electric service requirements.	
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following:	
(A) A description of the potential demand-side resource, including its costs, characteristics, and parameters.	
(B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.	
(C) The customer class or end-use, or both, affected by the demand-side resource.	
(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.	
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.	
(F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following:	Section 7, Appendix D
(A) Identification and description of the supply-side resource considered, including the following:	
(i) Size in megawatts.	
(ii) Utilized technology and fuel type.	
(iii) Energy profile of nondispatchable resources.	
(iv) Additional transmission facilities necessitated by the resource.	
(B) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Section 7.1
(C) A description of significant environmental effects, including the following:	Section 6.5
(i) Air emissions.	
(ii) Solid waste disposal.	
(iii) Hazardous waste and subsequent disposal.	
(iv) Water consumption and discharge.	
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following:	Section 6.7

(A) The type of the transmission resource, including whether the resource consists of one (1) of the following:	
(i) New projects.	
(i) Upgrades to transmission facilities.	
(ii) Efficiency improvements.	
(iii) Smart grid technology.	
(B) A description of the timing, types of expansion, and alternative options considered.	
(C) The approximate cost of expected expansion and alteration of the transmission network.	
(D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby increasing the utilization of geographically constrained cost effective resources.	
(E) A description of how:	Section 6.4, Section 6.7
(i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and	
(ii) RTO planning and implementation processes affect the IRP.	
170 IAC 4-7-7 Selection of resources	
To eliminate nonviable alternatives, a utilityshall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	Section 7.6, 7.7, Appendix D
170 IAC 4-7-8 Resource portfolios	
(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider:	Section 8
(1) risk;	
(2) uncertainty;	
(3) regional resources;	
(4) environmental regulations;	
(5) projections for fuel costs;	
(6) load growth uncertainty;	
(7) economic factors; and	
(8) technological change.	
(b) With regard to candidate resource portfolios, the IRP must include the following:	

(1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(26) of this rule.	
(2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics.	
(3) The present value of revenue requirement for each candidate resource portfolio in dollars per kilowatt-hour delivered, with the interest rate specified.	
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following:	Section 9
(1) A description of the utility's preferred resource portfolio.	
(2) Identification of the standards of reliability.	
(3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio.	
(4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of:	
(A) safety;	
(B) reliability;	
(C) risk and uncertainty;	
(D) cost effectiveness; and	
(E) customer rate impacts.	
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently, and cost-effectively meets the electric system demand taking cost, risk, and uncertainty into consideration.	
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following:	
(A) Operating and capital costs of the preferred resource portfolio.	
(B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	
(C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.	
(D) The utility's ability to finance the preferred resource portfolio.	
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability, and portfolio risk and uncertainty, including the following:	
(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to:	Section 9
(i) environmental and other regulatory compliance;	
(ii) reasonably anticipated future regulations;	

(iii) public policy;	
(iv) fuel prices;	
(v) operating costs;	
(vi) construction costs;	
(vii) resource performance;	
(viii) load requirements;	
(ix) wholesale electricity and transmission prices;	
(x) RTO requirements; and	
(xi) technological progress.	
(B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools, and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	Section 5.13
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following:	Section 9
(A) Demand for electric service.	
(B) Cost of new supply-side resources or demand-side resources.	
(C) Regulatory compliance requirements and costs.	
(D) Wholesale market conditions.	
(E) Fuel costs.	
(F) Environmental compliance costs.	
(G) Technology and associated costs and penetration.	
(H) Other factors that would cause the forecasted relationship between supply and demand for electric service to be in error.	
170 IAC 4-7-9 Short term action plan	
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	Section 10
(b) The short term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(10) of this rule, where the utility must take action or incur expenses during the three (3) year period.	
(c) The short term action plan must include, but is not limited to, the following:	
(1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:	
(A) The objective of the preferred resource portfolio.	
(B) The criteria for measuring progress toward the objective.	

(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10 and 170 IAC 4-8-1 et seq. and consistent with the utility's longer resource planning objectives.	
(3) The implementation schedule for the preferred resource portfolio.	
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	
(5) A description and explanation of differences between what was stated in the utility's last filed short term action plan and what actually occurred.	

Appendix Vol. 2 – Load Forecast Model Equations and Statistical Test Results

Appendix Vol. 3 – Confidential Exhibits

Exhibit A	FERC Form 715
Exhibit B	Projected Fuel Costs
Exhibit C	Short Term Large Industrial Energy Models
Exhibit D	Long-term retail and wholesale forecast models data
Exhibit E	Short Term and Long term Wholesale Energy Models
Exhibit F	OVEC 2030 Supplemental Analysis

Appendix Vol. 4 – Public Participation Process