Attachment 1.1 Non-Technical Summary

2022/2023

Integrated Resource Plan

CenterPoint® Energy

Executive Summary (Non-Technical Summary)

I. Introduction

Southern Indiana Gas and Electric Company d/b/a CEI South a CenterPoint Energy Company's ("CEI South") 2022/2023 Integrated Resource Plan is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's recent orders related to the preferred portfolio described in CEI South's previous 2019/2020 Integrated Resource Plan ("IRP") both in the preparation of this IRP and the planning process that necessarily preceded the report. The analysis and its conclusions explained in this IRP demonstrate that CEI South can most cost-effectively meet the electric demands of its retail customers by continuing to transition its generation fleet from primarily coal-based generation to a generation mix that is much more diverse. The analysis demonstrates that customers receive a better balance of affordability and reliability by investing in new generation resources and transitioning existing resources to new fuel sources compared to the on-going necessary investment and future cost risk of continuing to run its existing coal-fired generation facilities.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. The preferred portfolio in CEI South's previous 2019/2020 IRP concluded a generation transition was needed, calling for replacement of the majority of CEI South's coal fleet by the end of 2023 with 700-1,000 MWs of solar, 300 MWs of wind, energy efficiency and two gas combustion turbines while retaining FB Culley 3 coal resource. CEI South has begun implementing this 2019/2020 IRP by filing several cases seeking approval to (1) purchase a BTA to own and operate a 191 MW solar project located on its system (the "Posey County Solar Project"), (2) purchase a BTA to own and operate a 130 MW solar project located in Pike County (the "Crosstrack Solar Project"), (3) purchase a BTA to own and operate a 200 MW wind project located in MISO ("Midcontinent Independent System Operator") zone 4 (the "Wind Project"), (4) signed purchase power agreements ("PPA") for 3 solar facilities totaling 430 MWs for the Warrick County Solar Project, the Knox County Solar Project, and the Vermillion County Solar project. (5) CEI South sought and received approval for two combustion gas turbines at A.B. Brown power plant, totaling 460 MWs. Each of these projects were consistent with the 2019/2020 IRP and, as noted below, this IRP affirms the direction taken by CEI South.

The Commission approved issuance of certificates of public convenience and necessity (“CPCNs”) authorizing the construction of the Posey Solar Project and Cross Track Solar Projects and approved the solar PPAs. Government action and market forces have necessitated renegotiation of several of the renewable projects and delayed their in-service dates. CEI South has worked with the project developers to obtain revised pricing and in-service dates and has sought IURC approval of the changes for the Posey County, the Knox County, the Vermillion County, and the Warrick County Solar Projects. CEI South could have refused to work with the developers of these projects, but the poor economics would have resulted in the developers terminating their relationship with CEI South. Responses to CEI South’s recent request for proposal demonstrated replacement projects would have been higher cost and brought later in-service dates. This is a significant concern for CEI South and its customers due to looming compliance deadlines for its existing generation resources. As of the date of this IRP, the IURC approved increased cost for the Knox County Solar Project, and the OUCC did not oppose the cost increases for the Warrick County Solar Project or the Vermillion County Solar Project. The Posey Solar Project and the Wind Project are awaiting approval by the IURC.

CEI South began its 2022/2023 IRP process in early 2022 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company’s exploration included significant input and dialogue with stakeholders. While starting with 2019/2020 IRP framework as a basis for the 2022/2023 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to the following:

- increased stakeholder engagement in the issuance of an All-Source RFP to provide current market project pricing to be utilized in IRP modeling and potential projects to pursue, particularly for renewable resources such as wind, solar, and battery storage;
- increased participation and collaboration from stakeholders using tech-to-tech calls and associated file sharing throughout the process for timely feedback on inputs and resource evaluation criteria;
- an encompassing analysis of wholesale market dynamics that accounts for MISO developments and market trends, including MISO's new seasonal construct, which includes four seasons;
- at stakeholder request, CEI South engaged 1898 & Co. to utilize a new sophisticated IRP modeling tool, Encompass, which provided several benefits (increased transparency for stakeholders, more efficient modeling runs and maintaining the ability to produce probabilistic modeling); and
- a robust risk analysis, which encompasses a broad consideration of risks and an exploration of resource performance over a wide range of potential futures with additional sensitivity analyses.

Based on this planning process and detailed analysis, CEI South has selected a preferred portfolio plan that continues to diversify the resource mix for its generation portfolio. This portfolio includes the addition of significant solar and wind energy resources in the near to midterm, the conversion of FB Culley 3 from coal to natural gas by 2027, and continued investment in energy efficiency and demand response resources. The conversion of Culley Unit 3 allows CEI South to maintain this critical capacity resource, protecting customers from a volatile MISO capacity market and considerably lowering CO_2 emissions. FB Culley 3 will be available for peak periods, enabling CEI South to maintain constant electric supply during potentially extended periods of low output from renewable energy sources. The converted unit will include firm gas supply and allow CEI South to continue to utilize existing equipment and interconnection to the MISO system. Additionally, CEI South has placed an emphasis on exploring demand response options to provide a cost effective capacity resource for our customers. The company is in discussions with a demand response ("DR") aggregator for commercial and industrial DR and plans to request a pilot in its upcoming rate case to explore time based rates. Indicative DR amounts were included for IRP planning purposes. CEI South's preferred portfolio is projected to save customers nearly $80 million over the next 20 years compared to continuing with this last existing coal unit operated by CEI South. This builds on savings identified in the last IRP. Additionally, the preferred portfolio reduces carbon dioxide stack emissions by approximately 88% by 2030 and 95% by 2035 when compared to projected 2023 levels. This fosters environmental stewardship and sustainability, while meeting customer expectations for clean energy that is reliable and affordable.

CEI South's preferred resource plan reduces risk through continued diversification, the cost to serve load over the next 20 years and provides flexibility to evaluate and respond to future needs through subsequent IRPs. The preferred portfolio has several advantages, including: 1) Converts CEI South's last remaining coal unit that it operates to natural gas by 2027. This saves customers money and dramatically lowers CO_2 output in the near term. FB Culley 3 can also provide resilient, dispatchable power to CEI South's system during long-duration weather events. Reliable, dispatchable power is very important as coal plants that have provided capacity in the past continue to retire in MISO Zone 6. 2) Energy supplied by this portfolio is generated primarily through renewable solar and wind projects by 2030, which can take advantage of Investment Tax Credits ("ITC") and the Production Tax Credits ("PTC"). ITCs and PTCs reduce portfolio costs and leverage current tax-advantaged assets. 3) The portfolio provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. The preferred portfolio also performed well under CO_2, methane constraints, and other related regulations. Like the CTs identified in the 2019/2020 IRP, the preferred portfolio is financially supported by a converted coal unit that will predominantly run during peak load conditions. This benefit provides a financial hedge against periodic instances of high market energy and MISO's volatile capacity market, while also providing reactive reserves and system reliability in times of extended renewable generation droughts, i.e., cloud cover and low wind. 4) It reasonably balances energy sales and purchases, ready to adapt to market shifts. 5) It includes new wind, solar, and demand response capacity when it is economic to the portfolio. 6) Finally, it is timely. The conversion of F.B. Culley 3 is projected to take no more than 6 months and can be completed by 2027.

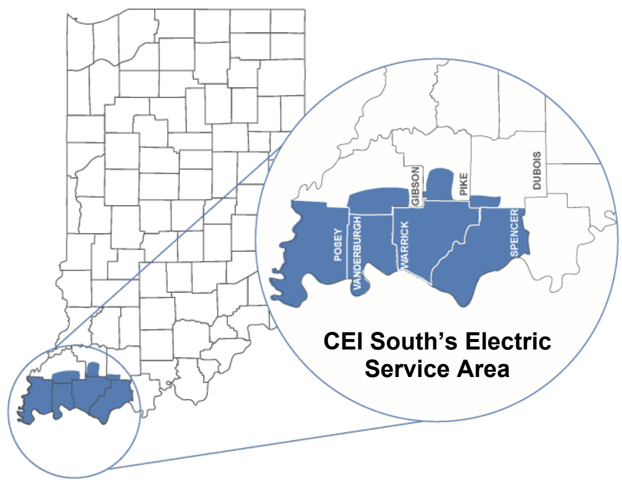
The resource options selected in this plan provide a bridge to the future. For example, the gas conversion allows battery storage technology to become more competitive in price and develop longer duration storage capabilities. Further, should there be a need for new baseload generation to accommodate a large load addition, one or both of the new CTs could be converted to a combined cycle gas turbine, a highly efficient energy resource.

The preferred portfolio also provides several off-ramps (future transitional inflection points) should they be needed. 1) CEI South plans to discontinue joint operations of Warrick 4 (“W4”) at the end of 2023 but continues to speak with Alcoa about a possible extension into 2025. This option could shield CEI South customers from costly purchases in a tight capacity market. As CEI South has worked through the generation transition plan, solar project Commercial Operation Dates (“COD”) have shifted, and there is still a need for capacity to complete phase one of the transition. Additionally, beyond delayed solar projects, time may still be needed for permitting contingency and construction of new combustion turbines, currently expected to be in service in MISO’s 2025/2026 planning period. 2) While Culley 3 is not scheduled to be retired within the timeframe of this analysis, including thermal dispatchable generation in this portfolio provides CEI South flexibility to evaluate this option in future IRPs. 3) CEI South will work to secure attractive renewable projects from the recent All-Source RFP and will likely require future RFPs to secure 200 MWs of additional wind and 200 MWs of additional solar resources by 2030. Issuing a future RFP provides two main benefits. It will provide the most up-to-date pricing for these renewables projects and attract more renewable options to select from, as some offered proposals are no longer available. Second, it provides CEI South additional time to better understand how the Inflation Reduction Act (“IRA”) effects the renewables markets, potentially unlocking more projects. Demand for wind and solar projects in Indiana is particularly high, which could lead to scarcity of projects if more potential developments do not enter the MISO queue.

The following preferred portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

II. CenterPoint Energy Overview

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in Southwestern Indiana. In 2022, approximately 43% of electric sales were made to large (primarily industrial) customers, 31% were made to residential customers and 26% were made to small commercial customers.



The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 1	245	Coal	1979	2023	44	Yes
A.B. Brown 2	240	Coal	1986	2023	37	Yes
F.B. Culley 2	90	Coal	1966	2025	57	Yes
F.B. Culley 3	270	Coal	1973	N/A	50	Yes
Warrick 4	150	Coal	1970	2023[2]	53	Yes
A.B. Brown 3	80	Gas	1991	N/A	31	

[1] All coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_X"), Particulate Matter (dust), and Mercury. All coal units are controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("H2S0$_4$") except F.B. Culley 2.
[2] Joint operations agreement expires 12/31/23

Unit	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date	Unit Age	Coal Unit Environmental Controls[1]
A.B. Brown 4	80	Gas	2002	N/A	21	
A.B. Brown 5	245	Gas	2025	N/A	N/A	
A.B. Brown 6	245	Gas	2025	N/A	N/A	
Blackfoot[3]	3	Landfill Gas	2009	N/A	14	
Fowler Ridge	50	Wind PPA	2010	N/A	13	
Benton County	30	Wind PPA	2007	N/A	16	
Oak Hill[4]	2	Solar	2018	N/A	5	
Volkman Rd[5]	2	Solar	2018	N/A	5	
Troy	50	Solar	2021	N/A	2	
Rustic Hills II Solar[6]	100	Solar	2025	N/A	N/A	
Posey Solar	191	Solar	2025	N/A	N/A	
Wheatland Solar[7]	150	Solar	2024	N/A	N/A	
Vermillion Rise Solar[8]	185	Solar	2025	N/A	N/A	
Crosstrack Solar	130	Solar	2025	N/A	N/A	
Future Wind	200	Wind	2025	N/A	N/A	

III. Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required by IURC rules. The IRP describes the analysis process used to evaluate the best mix of generation and energy efficiency resources (resource portfolio) to meet customers' needs for reliable, affordable, environmentally sustainable power over the next 20 years. The IRP can be thought of as a compass setting the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups and environmental advocacy groups. CEI South continues to place an emphasis

[3] The Blackfoot landfill gas generators are connected at the distribution level.
[4] Oak Hill Solar is connected at the distribution level.
[5] Volkman Rd. Solar is connected at the distribution level.
[6] Warrick County Solar Project
[7] Knox County Solar Project
[8] Vermillion County Solar Project

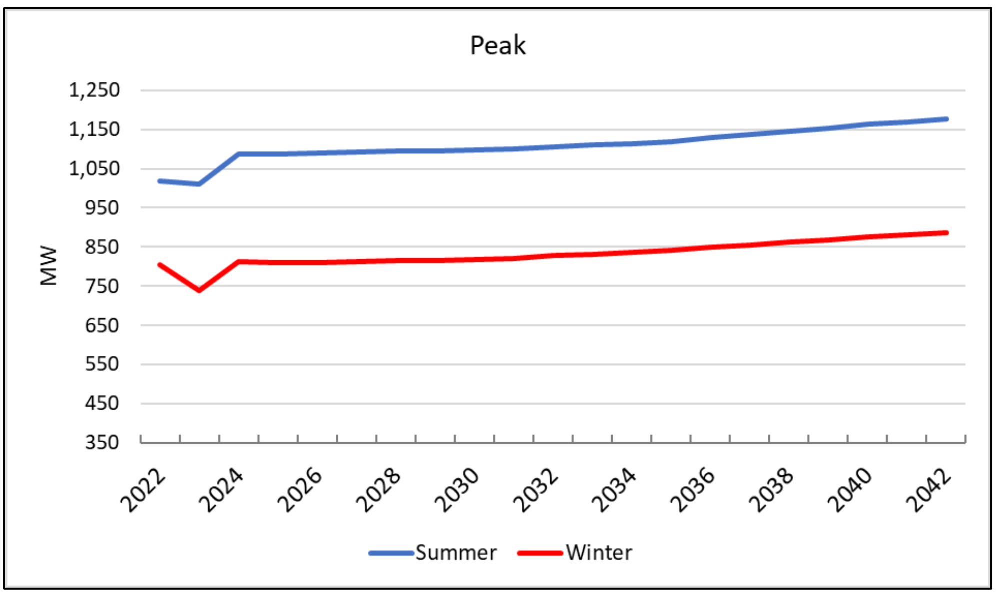
on reliability, affordability, resiliency, stability, risk, resource diversity, and environmental sustainability. The IRP process has become increasingly complex in nature as MISO implements updated resource accreditation methodologies to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

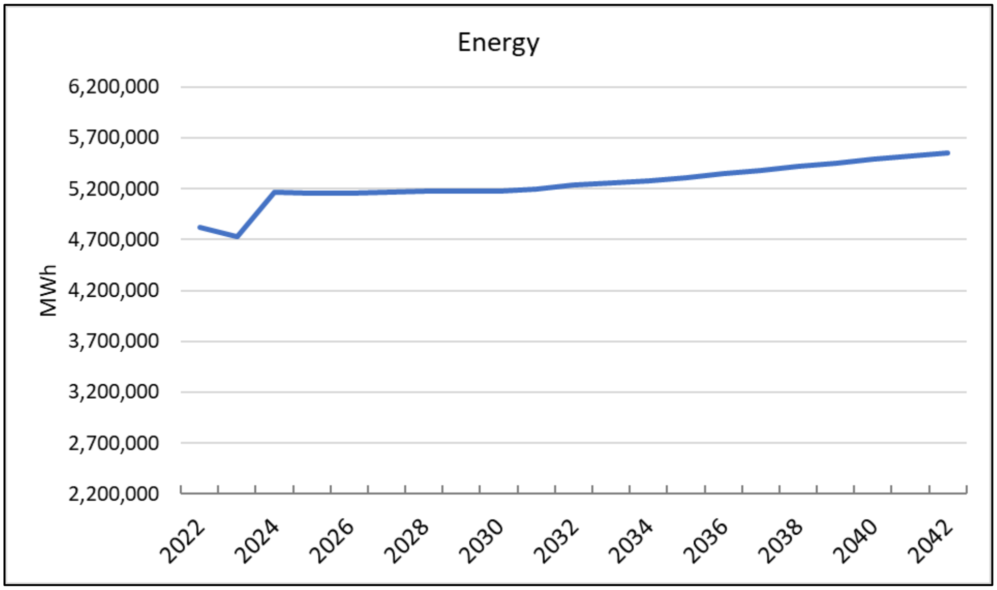
A. Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Energy is typically measured in Megawatt hours ("MWh") and demand is typically measured in Megawatts ("MW"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation and energy efficiency resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.

Historically, IRPs have focused on meeting customer demand in the summer, which is typically when reserve margins are at a minimum. As the regional resource mix changes towards intermittent (variable) renewable generation, it is important to ensure resources are available to meet this demand seasonally in all hours of the year, particularly in the times of greatest need (summer and winter). MISO functions as the regional transmission operator for 15 Midwestern and Southern states, including Indiana (also parts of Canada). In recognition of MISO's ongoing evaluation of how changes in the future resource mix impact seasonal reliability, CEI South ensured its preferred portfolio would have adequate reserve margins for meeting demand in all four seasons, consistent with MISO's recently approved seasonal construct beginning in the 2023/2024 planning year on June 1, 2023. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability, beyond the seasonal construct.

CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles. Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by 0.7% per year. Winter peak demand grows at a slightly slower pace of 0.5%.





B. Resource Options

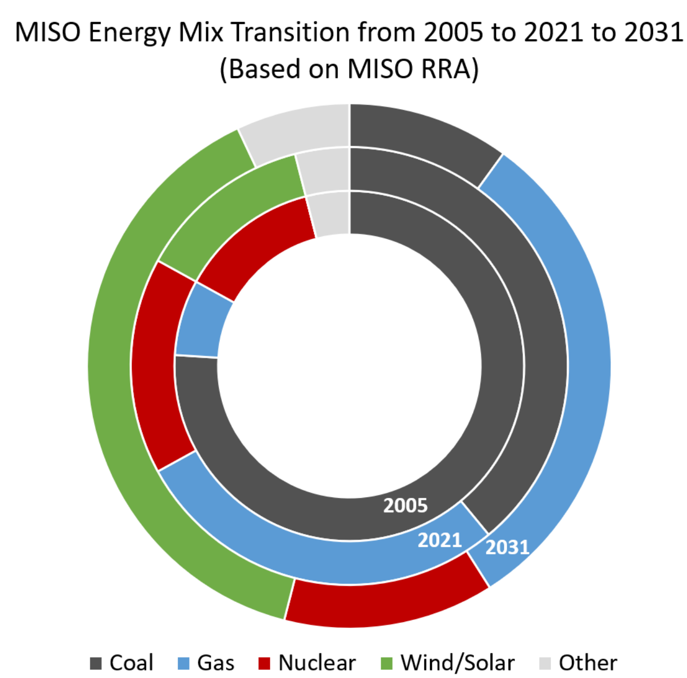
The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 142 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, demand response, wind, gas, nuclear, and coal. These project bids provided up-to-date, market-based information to inform the analysis and provide actionable projects to pursue to meet customer needs in the near to midterm. Additionally, CEI South utilized other information sources for long term costs and operating characteristics for these resources and others over the entire

- Battery Storage
- Coal
- Energy Efficiency/ Demand Response
- Hydro Electric
- Natural Gas
- Nuclear
- Wind and Solar

20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 2 and/or 3 coal units to natural gas, various other natural gas resources, conversion of AB Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries[9]. Every IRP is a snapshot in time producing a direction based on the best information known at the time. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the passage of the IRA, recent volatile gas prices, high inflation, projected high penetration of intermittent renewable resources, recent increased costs for renewables projects due to demand / supply chain issues, the future of coal resources with more restrictive air regulations, new technologies, and rapid changes in the MISO market to adapt and help ensure reliability.

i. Industry Transition

Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation, used primarily to meet the needs during peak demand conditions in 2005, to approximately 28% of total generation in 2021[10]. Meanwhile, the cost of renewable energy has declined dramatically over this time period due to improvements in technology and helped by



[9] Not commercially viable at this time
[10] MISO 2021 State of the Market Report, Potomac Economics, June 2022, page 6 https://cdn.misoenergy.org/2021%20State%20of%20the%20Market%20Report625295.pdf

government incentives in the forms of the PTC and the ITC for renewable energy resources such as wind and solar, both of which have been extended and expanded by the IRA.

The move toward renewable and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Additionally, older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with Environmental Protection Agency ("EPA") regulations. Two recent rule changes are further examples of the continued pressure on coal. EPA finalized revisions to the Cross-State Air Pollution Rule and the Good Neighbor Rule which require further reductions in emissions of NOx during the Ozone Season. EPA has also recently proposed revisions to the Mercury Air Toxics rule that could further ratchet down particulates for F.B. Culley by 2026-2027and on January 6, 2023 EPA proposed a new rulemaking to reduce the National Ambient Air Quality Standard PM2.5 standard and review state's attainment designations. It can be challenging for F.B. Culley to maintain compliance under current regulations and will be more difficult to continue operating the unit on coal in 2027 and beyond. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has driven unit retirements. Based on these and other major factors, according to MISO's Regional Resource Assessment, they project wind and solar to contribute up to 42% of the energy in 2031[11]. Some large nuclear plants remain but have also found it challenging to compete on cost.

[11] MISO 2022 Regional Resource Assessment, November 2022, page 6 https://cdn.misoenergy.org/2022%20Regional%20Resource%20Assessment%20Report627163.pdf

ii. Changing Market Rules to Help Ensure Reliability

MISO recognizes these major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have over production (more energy produced than is needed at the time) and other periods will have low to no renewable energy production, requiring dispatchable resources to meet real time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future. Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing resource portfolio and the risks MISO faces there is an increased importance of ensuring there are adequate attributes available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained with the changing resource portfolio, MISO implemented a seasonal resource adequacy construct for the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("$EFOR_d$") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources has also seen changes with MISO signaling it will continue to revise the accreditation approach for renewables for upcoming planning years. MISO continues to study how this transition will affect the electrical grid and what is needed to maintain reliable service, as renewables penetrations reach 30-50%. Possible ramifications include challenges to the ability to maintain acceptable voltage and thermal limits on the grid.

CEI South has accounted for these changes by incorporating the seasonal construct and accreditation approach into the Encompass model and validating that portfolios in this analysis provide sufficient resources to meets its MISO obligations[12] in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations for each option.

iii. Battery Storage and Transmission Resources

Increasingly, utilities are considering the opportunity to add battery storage to resource portfolios to help provide the availability, flexibility and visibility to support the move to more reliance on intermittent renewable resources. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature and as the auto industry creates economies of scale by increasing production to meet the anticipated demand for electric vehicles. However, L-ion batteries continue to evolve. Lithium-ion batteries relying on iron-based cathodes are emerging and are expected to provide nearly 50% of the global demand by 2027. This move is occurring because of the relative abundance and sourcing of iron compared to Cobalt. Large scale batteries for utility applications have begun to emerge around the country, particularly where incentives are available to lower the cost of this emerging technology or for special applications that improve the economics. This technology will continue to evolve over the next decade as competing alternatives are put into operation and evaluated.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining

[12] Some portfolios have a heavy reliance on the market for energy.

the reliability of the transmission system. CEI South has installed a 1 MW battery designed to capture energy from an adjacent solar project. This test project has provided information regarding the ability to store energy for use during the evening hours to meet customer energy demand. Along with the benefits provided by this technology, there are some limitations to keep in mind as utility scale battery storage is still evolving. Commercially feasible batteries remain short duration, typically four hours. There are some longer-duration batteries that show promise, such as iron air, but these are still very expensive and not proven on a utility-scale. Future IRPs will continue to monitor for when these technologies become commercially viable. Additionally, safety standards are being developed and fire departments are being trained for the fire risk posed by L-ion batteries. Other chemistries are being developed to account for this issue but are not commercially imminent. Moreover, batteries today are a net energy draw on the system. L-ion can produce about 85-95 percent of the energy that is stored in them. Part of this loss is due to the need to be well ventilated, cool and dry, which takes energy. Batteries are promising and have their place in current and future energy infrastructure, but they do not yet replace the need for other forms of dispatchable generation during extended periods without sun and wind. Recent MISO changes in rules and mechanisms are geared towards meeting the worst week in each season. There is a need for multi-day storage to provide similar benefits to dispatchable generation. Other issues to be followed are how the penetration will affect accreditation based on Effective Load Carrying Capability (“ELCC”), which is expected to go down over time. CEI South conducted a sensitivity analysis to evaluate the cost impact of decreasing accreditation to 75% from 95%. The sensitivity demonstrated that cost to portfolios that rely on batteries would go up as accreditation goes down. Additionally, availability of batteries may not be 95% as modeled within this IRP. Information from California’s experience suggests performance of batteries could be much lower. CEI South’s All-Source RFP included bids for stand-alone batteries and batteries connected to solar resources and will continue to track developments in this space.

C. Uncertainty/Risk

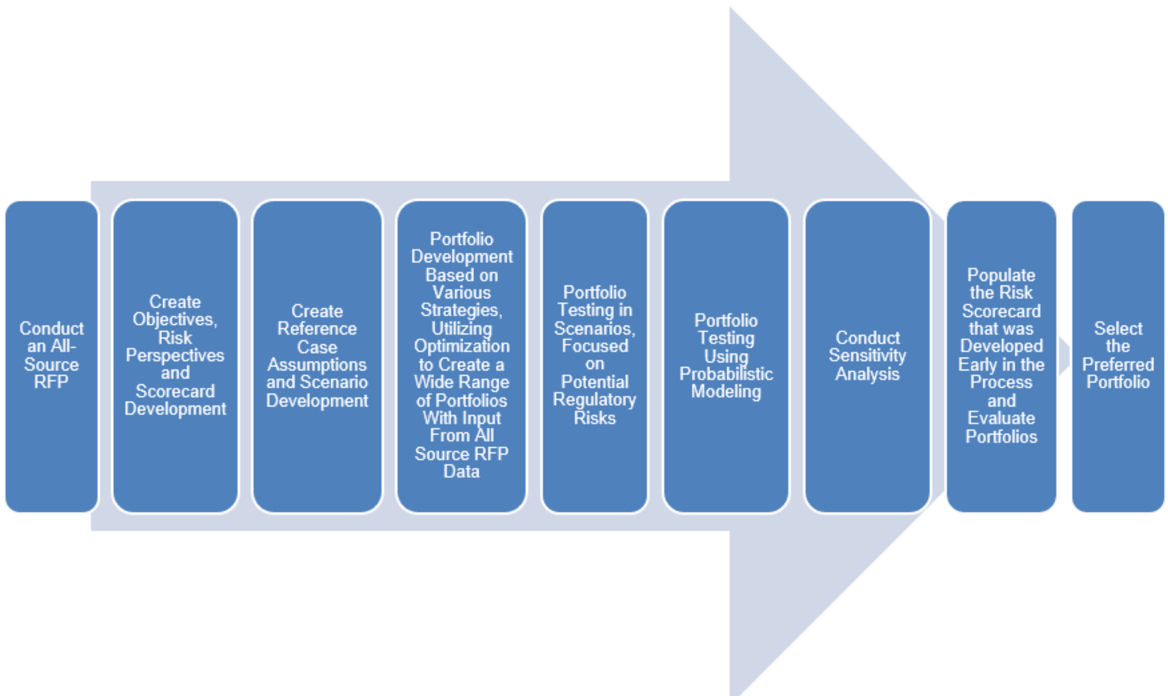
The future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the best resource mix of generation and energy efficiency to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

IV. Analysis

CEI South's analysis included a step-by-step process to identify the preferred portfolio. The graphic below summarizes the major steps which included the following:

1. Conduct an All-Source RFP to better understand resource cost and availability.
2. Work with stakeholders to develop a scorecard as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Work with stakeholders to develop a wide range of future states, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Work with stakeholders to develop a wide range of portfolios for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conduct a risk analysis, including deterministic and probabilistic modeling with sensitivity analysis.

6. Utilize the quantitative scorecard measures and judgment to select the preferred portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).



V. Stakeholder Process

CEI South continued to improve stakeholder engagement with a series of technical meetings with any stakeholder group willing to sign a Non-Disclosure Agreement ("NDA") and participate with in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. The process was reevaluated based on early feedback with stakeholders about what has worked well with other utilities throughout the state. CEI South also reviewed comments in the Director's report on CEI South's last IRP and ongoing Contemporary Issues meetings hosted by the IURC. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.

As in the last IRP, each of the first three stakeholder meetings began with stakeholder feedback. CEI South would review requests/comments since the last stakeholder meeting and provide feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South made a point to further discuss and explain why not. Notes for each meeting were included in question and answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (irp@centerpointenergy.com) and with one off phone calls/meetings in between each public stakeholder meeting by request, in addition to tech-to-tech meetings mentioned above.

While maintaining the virtual option to participate, CEI South thought it was important to offer face to face meetings post the COVID-19 situation of recent years. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to Southern Indiana or did not wish to participate in person. Dates and topics covered are listed below:

August 18, 2022	October 11, 2022	December 13, 2022	April 26, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs*	• Final Reference Case and Scenario Modeling Results • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

*Provided final draft modeling file on December 20, 2022 to stakeholders that signed an NDA as part of the tech-to-tech group. Final deterministic modeling files were provided on March 7, 2023, and final stochastic files were provided on April 21, 2023.

Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the preferred portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This along with providing modeling inputs along the way helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process. CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios. CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding a metric that highlights risk from exposure to energy generated by coal and gas, and adopting a metric that measures total CO_2 equivalent tons emitted into the atmosphere over the full planning year. Finally, multiple adjustments were made to modeling inputs and assumptions based on direct stakeholder feedback. The table below shows key stakeholder requests made during the process and CEI South's response.

Request	Response
Allow All-Source RFP respondents to update their proposals to account for the IRA	RFP respondents were given the opportunity to update their bids (updated results were incorporated into the IRP)
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	Cumulative CO_2 equivalent (stack emissions) were added to the scorecard along with CO_2 intensity
Add a fuel cost risk measure and objective to the scorecard	Cost Risk metric was included in the scorecard, including both fuel risk and 95% percentile cost risk

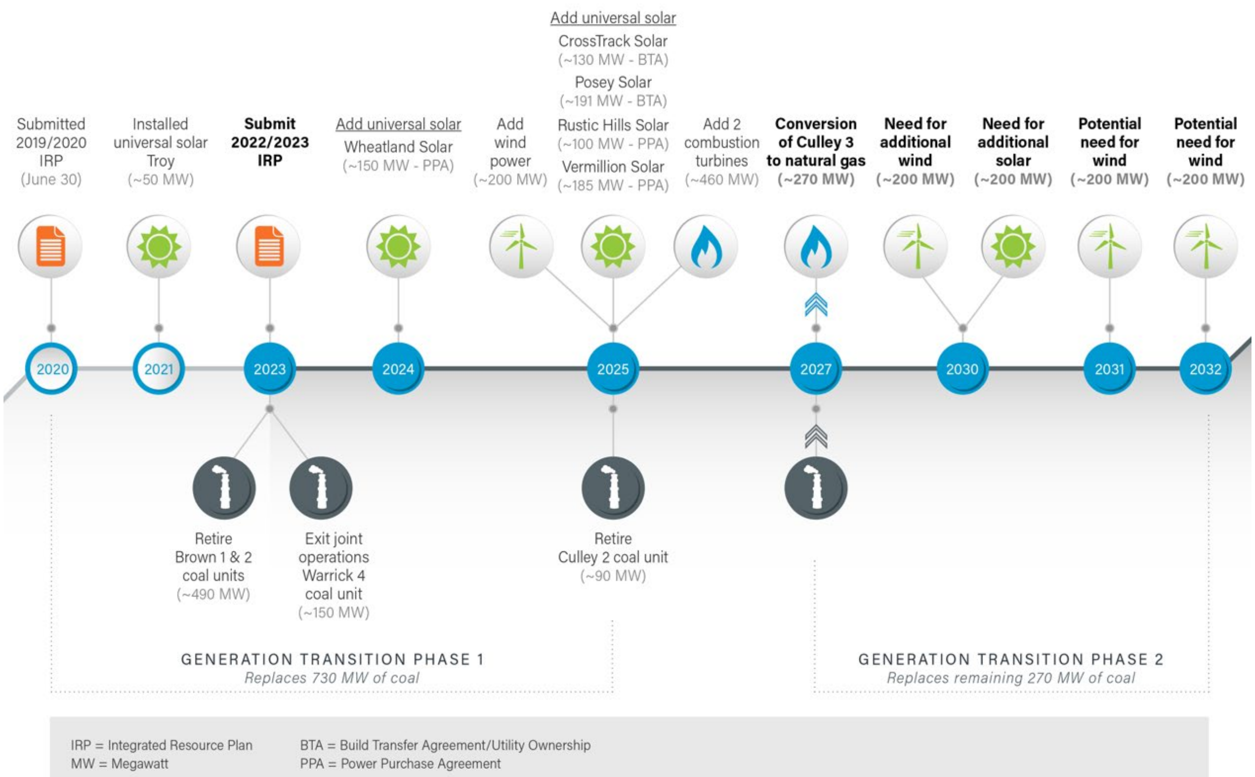
Request	Response
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South included 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR registered with MISO. CEI South is engaged in conversations with a demand response aggregator to capture the potential of C&I demand response to further diversify our resource mix
CenterPoint should include demand response using the same methodology as AES. Implement residential rate programs (critical peak pricing, TOU, etc.) soon	CenterPoint has adopted the AES methodology and DR is aligned with peers to incorporate indicative TOU pilots. CEI South is planning to evaluate a TOU rate in the future through a pilot
In the summer of 2022, the reference case forecasts for coal and natural gas prices showed a decline in the near term and do not reflect current pricing	Gas and coal price forecasts were updated as new forecasts became available in late fall of 2022
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	CEI South found it plausible that coal prices could be higher in a high regulatory scenario and updated the price path to be higher than reference case in the high regulatory scenario
Revise the wind profiles being used in the model to differentiate between the output of northern Indiana and southern Indiana wind	The output profiles for wind resources were updated (increased) to better align with the information received from wind resources in the All-Source RFP

Request	Response
Explore alternative retirement dates for Culley 3	Culley 3 will be evaluated in scenarios with a potential retirement date of 2029 (pulled forward from 2030). Also included an alternative that converts F.B. Culley 3 to natural gas by 2027
Update modeling to reflect ITC storage year one	CEI South modeled the ITC benefit for storage in year one
Include full monetization of ITC for hydro resources	Included
Request for continued on-going dialogue following the December public stakeholder meeting	Held a tech-to-tech meeting on February 28, 2023 to provide updated modeling files, additional input files, and portfolios for consideration in the risk analysis to stakeholders for review and comment
Include site -specific assumptions for the energy community bonus for PTC and ITC associated with the IRA	CEI South ran various resource capital costs and tax credit qualification sensitivities to determine the impact of these changes on future resource decisions
Evaluate a portfolio with hydroelectric	Hydroelectric was not selected as a least cost resource within modeling. Several portfolios with hydro were evaluated, but they were higher cost and not included in the risk analysis
Capital costs should not be varied stochastically	An alternate process was used for capital and CO_2
Adjust the scorecard to include near and long-term energy purchases/sales	Adjusted

Meeting materials for each meeting can be found on www.centerpointenergy.com/irp and in Technical Appendix Attachment 3.1 Stakeholder Materials.

VI. The Preferred Portfolio

The Preferred Portfolio is the second evolution to the generation transition plan to move away from coal to a more sustainable portfolio of resources. The recommendation is to convert the remaining 270 MWs of coal generation to natural gas and to provide demand response resources for low-cost capacity and continue to add clean, renewable wind and solar resources by 2030, while maintaining energy efficiency programs at similar levels. Beyond 2030, 400 MWs of additional wind is called for.

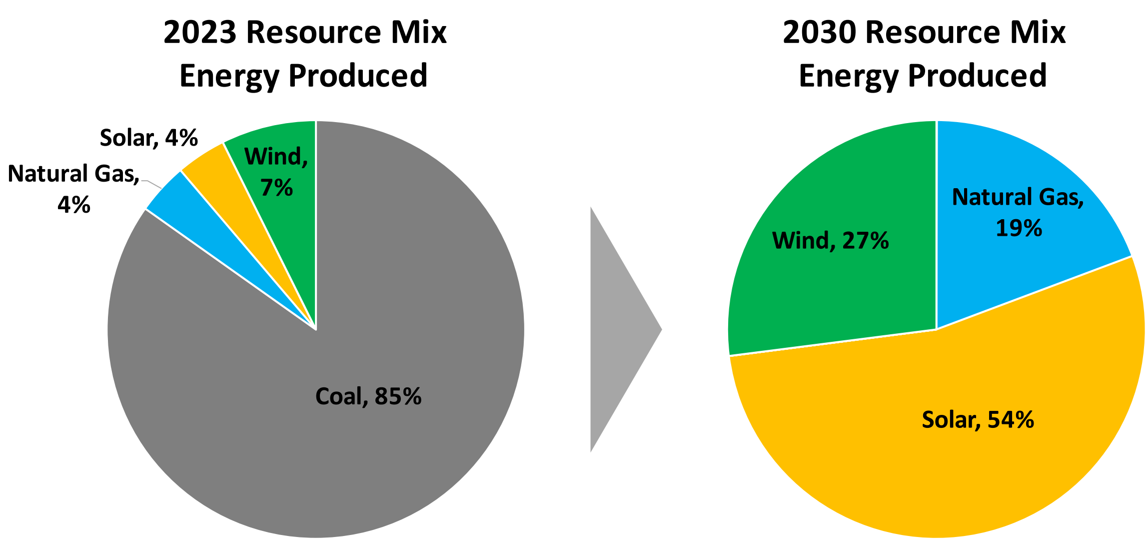


This preferred portfolio:

- Eliminates dependence on coal-fired generation in a prompt timeframe yet provides the flexibility to adapt to changes in technology in the future.
- Maintains reliability and allows customers to enjoy the benefits of renewable energy, while ensuring continued reliable service as CEI South continues to move toward higher levels of intermittent renewable energy in the future. Dispatchable generation with firm gas service at F.B. Culley will allow this resource to be available to meet peak conditions during long duration weather events, providing resiliency.
- Saves customers nearly $80 million over the next 20 years when compared to continued operation of F.B. Culley with coal and avoids $170 million of cost risk over this time period. Eliminates risk of additional cost to comply with currently proposed final environmental rules that become applicable to Culley 3 in 2027 and potential new regulations as EPA continues to focus on environmental concerns associated with coal-fired generation.
- Reduces CO_2 equivalent emissions, which includes methane, by nearly 95% over the next 20 years. Direct carbon emissions are reduced 98% from 2005 levels by 2035. The portfolio prevents over 9 million tons of CO_2 from entering the atmosphere as compared to continuing to run F.B. Culley 3 with coal.
- Includes a diverse mix of resources (solar, wind and energy efficiency, supported by fast-start gas, peaking gas generation, and demand response), mitigates the impacts of extended periods of limited renewable generation and protects against overreliance on the market for energy and capacity.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry, includes a multi-year build out of resources on several sites and maintains the option to replace Culley 3 in the future when appropriate based on continual evaluation of available technology and changing conditions.
- Provides the flexibility to adapt to future environmental regulations or upward shifts in fuel prices relative to Reference Case assumptions. The preferred portfolio

performed consistently well across a wide range of potential future environmental regulations, including CO_2, methane and fracking.

- Maintains tax base in Warrick County, which is particularly important to the local school system in that county.
- Allows for continued use of existing plant assets, helping to avoid potential future stranded assets.
- Continues CEI South's energy efficiency programs with near term energy savings of 1.1% of eligible sales and further long-term energy savings opportunities identified over the next 20 years. CEI South is committed to energy efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Explores new options to help manage loads in the future with the potential for new demand response resources, working with an aggregator to better partner with commercial and industrial customers to tap additional potential and include a pilot to evaluate the potential of time-based rates, which could provide new resources to help manage loads in the future.



VII. Next Steps

The preferred portfolio calls for CEI South to make additional changes to its generation fleet. Some of these changes require action in the near term. First, CEI South will seek approval from the IURC to convert F.B. Culley 3 from coal to natural gas. Second, the IRP calls for continuation of energy efficiency. CEI South filed a one year continuation of the 2021-2023 plan for 2024 and will file a 2025-2027 plan in early 2024 with the IURC, consistent with the IRP. Third, CEI South plans to issue a new RFP in 2024 to pursue an additional 200 MWs of wind generation and 200 MWs of solar generation to be in service by 2030. CEI South continues to evaluate the potential to work with industrial customers who would like on-site solar generation. CEI South will evaluate including a portion of the new solar for this purpose. Given the long lead times for these projects and the need for energy that they produce, CEI South will begin pursuing these renewable projects ahead of the next IRP. These filings will be consistent with the preferred portfolio. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the preferred plan.

CEI South’s plan must be flexible, as several items are not certain at this time.

- The timing of exiting joint operations of the Warrick 4 coal plant could change. The plant is jointly owned with Alcoa and as such, CEI South continues to talk to Alcoa about its plans.
- Competition for renewable projects is steep, with multiple, ongoing RFP processes in the state of Indiana and the passage of the IRA. CEI South will continue to actively seek cost competitive projects for the benefit of our customers, consistent with the preferred portfolio.
- Finally, MISO continues to evaluate the accreditation of resources. CEI South will continue to follow developments.

Attachment 1.2 CEI South Technology Assessment Summary Table

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS PRELIMINARY - NOT FOR CONSTRUCTION AUGUST 2022						
PROJECT TYPE	**1x F Class Frame SCGT - Natural Gas**		**1x G/H Class Frame SCGT - Natural Gas**		**1x J-Class Frame SCGT - Natural Gas**	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit
Number of Gas Turbines/Engines/Units	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F.05		GE 7HA.01		GE 7HA.02	
Capacity Factor, %	Peaking (10%)		Peaking (10%)		Peaking (10%)	
Startup Time to Base Load, min (Note 1)	11		10		10	
Startup Time to MECL, min (Note 2)	8		8		8	
Cold Startup Time to SCR Compliance, min (Note 2)	45		45		45	
Maximum Ramp Rate, MW/min (Online)	40		55		60	
Book Life, Years	35		35		35	
Equivalent Planned Outage Rate, % (Note 3)	5.5%		5.5%		5.5%	
Equivalent Forced Outage Rate, % (Note 3)	0.7%		0.7%		0.7%	
Equivalent Availability Factor, % (Note 3)	93.8%		93.8%		93.8%	
Assumed Land Use, Acres	30	15	30	15	30	15
Fuel Design	Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)		Dual Fuel (Natural Gas and Fuel Oil)	
Heat Rejection	Fin Fan Heat Exchanger		Fin Fan Heat Exchanger		Fin Fan Heat Exchanger	
NO_x Control	Dry Low Nox / Nominal 9ppm Nox		Dry Low NOx / SCR		Dry Low NOx / SCR	
CO Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Particulate Control	Good Combustion Practice		Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	3		3		3	
ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION) (Note 4)						
Nominal Base Load Performance @59° F (ISO Conditions)						
Net Plant Output, kW	228,900	228,900	286,600	286,600	371,700	371,700
Net Plant Heat Rate, Btu/kWh (HHV)	10,010	10,010	9,260	9,260	9,240	9,240
Heat Input, MMBtu/h (HHV)	2,290	2,290	2,650	2,650	3,430	3,430
Nominal Min Load @ 59° F (ISO Conditions)						
Net Plant Output, kW	98,600	98,600	86,000	86,000	111,500	111,500
Net Plant Heat Rate, Btu/kWh (HHV)	13,330	13,330	13,580	13,580	13,630	13,630
Heat Input, MMBtu/h (HHV)	1,310	1,310	1,170	1,170	1,520	1,520
Base Load Performance @ 20° F (Winter Design)						
Net Plant Output, kW	238,400	238,400	295,300	295,300	383,700	383,700
Net Plant Heat Rate, Btu/kWh (HHV)	9,810	9,810	9,160	9,160	9,120	9,120
Heat Input, MMBtu/h (HHV)	2,340	2,340	2,710	2,710	3,500	3,500
Min Load Operational Status @ 20° F (Winter Design)						
Net Plant Output, kW	105,600	105,600	88,600	88,600	115,100	115,100
Net Plant Heat Rate, Btu/kWh (HHV)	13,180	13,180	13,840	13,840	13,840	13,840
Heat Input, MMBtu/h (HHV)	1,390	1,390	1,230	1,230	1,590	1,590
Base Load Performance @ 90° F (Summer Design)						
Net Plant Output, kW	210,500	210,500	265,300	265,300	345,700	345,700
Net Plant Heat Rate, Btu/kWh (HHV)	10,170	10,170	9,450	9,450	9,430	9,430
Heat Input, MMBtu/h (HHV)	2,140	2,140	2,510	2,510	3,260	3,260
Min Load Operational Status @ 90° F (Summer Design)						
Net Plant Output, kW	93,100	93,100	84,000	84,000	109,500	109,500
Net Plant Heat Rate, Btu/kWh (HHV)	13,600	13,600	13,640	13,640	13,650	13,650
Heat Input, MMBtu/h (HHV)	1,270	1,270	1,150	1,150	1,490	1,490
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$163**	**$109**	**$200**	**$150**	**$212**	**$151**
Owner's Costs, 2022 MM$	**$24**	**$9**	**$27**	**$12**	**$27**	**$12**
Owner's Project Development	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Owner's Operational Personnel Prior to COD	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Owner's Engineer	$0.8	$0.0	$0.8	$0.0	$0.8	$0.0
Owner's Project Management	$1.0	$0.0	$1.0	$0.0	$1.0	$0.0
Owner's Legal Costs	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Owner's Start-up Engineering and Commissioning	$1.5	$0.8	$1.6	$0.8	$1.6	$0.8
Land	$0.2	$0.1	$0.2	$0.1	$0.2	$0.1
Construction Power and Water	$0.5	$0.1	$0.5	$0.1	$0.5	$0.1

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
SIMPLE CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x F Class Frame SCGT - Natural Gas		1x G/H Class Frame SCGT - Natural Gas		1x J-Class Frame SCGT - Natural Gas	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit	First Unit	Next Unit
Permitting and Licensing Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Switchyard	$5.2	$1.7	$5.2	$1.7	$5.2	$1.7
Political Concessions & Area Development Fees	$0.5	$0.0	$0.5	$0.0	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$2.1	$1.9	$2.7	$2.5	$2.7	$2.5
Initial Fuel Inventory	$3.1	$3.1	$4.3	$4.3	$4.3	$4.3
Site Security	$0.4	$0.0	$0.4	$0.0	$0.4	$0.0
Operating Spare Parts	$5.5	$1.4	$6.5	$1.6	$6.5	$1.6
Permanent Plant Equipment and Furnishings	$0.3	$0.0	$0.3	$0.0	$0.3	$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Owner's Contingency (5% for Screening Purposes)	$1.1	$0.0	$1.3	$1.0	$1.3	$0.6
Total Project Costs, 2022 MM$	**$187**	**$118**	**$227**	**$162**	**$238**	**$163**
Total Project Costs, 2022 MM$ W AFUDC	**$210**	**$133**	**$256**	**$183**	**$268**	**$183**
EPC Cost Per kW, 2022 $/kW (Note 5)	**$710**	**$480**	**$700**	**$520**	**$570**	**$410**
Total Cost Per kW, 2022 $/kW (Note 5)	**$820**	**$520**	**$790**	**$570**	**$640**	**$440**
FIXED O&M COSTS (Note 6)						
Fixed O&M Cost - LABOR, 2022$MM/Yr	$0.9	$0.1	$0.9	$0.1	$0.9	$0.1
Fixed O&M Cost - OTHER, 2022$MM/Yr	$1.0	$0.4	$1.0	$0.4	$1.0	$0.4
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2022$/GT-hr or $/engine-hr (Notes 7)	$350	$350	$500	$500	$600	$600.0
Major Maintenance Cost, 2022$/GT-start	$9,500	$9,500	$17,900	$17,900	$26,500	$26,500
Major Maintenance Cost, 2022$/MWh	$1.60	$1.60	$1.80	$1.80	$1.60	$1.60
Catalyst Replacement Cost, 2022$/MWh	$0.00	$0.00	$0.20	$0.20	$0.20	$0.20
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE, Note 8)						
Total Variable O&M Cost, 2022$/MWh	$0.90	$0.90	$1.17	$1.17	$1.19	$1.19
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SCR Reagent, $/MWh	$0.00	$0.00	$0.27	$0.27	$0.29	$0.29
Other Consumables and Variable O&M, $/MWh	$0.90	$0.90	$0.90	$0.90	$0.90	$0.90
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 9)						
Turbine Only (lb/MMBtu, HHV)						
NO_X	0.04	0.04	0.01	0.01	0.01	0.01
SO_2	<0.002	<0.002	<0.002	<0.002	<0.003	<0.003
CO	0.020	0.020	0.014	0.014	0.014	0.014
CO_2	120	120	120	120	120	120

Notes

Note 1: Simple cycle GT starts are not affected by hot, warm or cold conditions. Simple cycle starts assume purge credits are available.
Note 2: MECL start time assumes the time for the GT to emissions compliance load (not stack compliance). The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels r
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Simple cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016.
Note 4: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 5: Capital costs are presented in 2022 USD $MM. $/kW values are calculated based on base load performance at ISO conditions.
Note 6: All Gas Turbine FOM costs assume 7 full time personnel for first unit. No additional personnel are included for the next unit(s). FOM costs do not include engine lease fees that may be available with LTSA, depending on OEM
Note 7: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. When average hours per start over the interval are <27, then major maintenance costs would be starts based.
Note 8: VOM assumes the use of temporarily trailers for demineralized water treatment, where applicable.
Note 9: Emissions estimates are shown for steady state operation at annual average conditions.
Note 10: Performance ratings are based on elevation of 120 ft above msl.
Note 11: Estimated Costs exclude decommissioning costs .

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x1 F Class CCGT - Unfired	1x1 F Class CCGT - Fired	1x1 G/H Class CCGT - Unfired	1x1 G/H Class CCGT - Fired	1x1 J Class CCGT - Unfired	2x1 J Class CCGT - Fired
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired
Number of Gas Turbines	1	1	1	1	1	2
Number of Steam Turbines	1	1	1	1	1	1
Representative Class Gas Turbine	GE 7F.05	GE 7F.05	GE 7HA.01	GE 7HA.01	GE 7HA.02	GE 7HA.02
Steam Conditions (Main Steam / Reheat)	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F	1,050 °F / 1,050 °F
Main Steam Pressure	2,400 psia	2,400 psia	2,400 psia	2,400 psia	2,400 psia	2,400 psia
Steam Cycle Type	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical	Subcritical
Capacity Factor (%)	70%	70%	70%	70%	70%	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 7, 8)	180	180	180	180	180	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 7, 8)	120	120	120	120	120	120
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 7, 8)	80	80	80	80	80	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (See note 4)	60	60	60	60	60	60
Maximum Ramp Rate, MW/min (Online)	35	35	40	40	55	110
Book Life (Years)	35	35	35	35	35	35
Equivalent Planned Outage Rate (%)	10.4	10.4	10.4	10.4	10.4	10.4
Equivalent Forced Outage Rate (%)	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Equivalent Availability Factor (%)	88.2%	88.2%	88.2%	88.2%	88.2%	88.2%
Assumed Land Use (Acres)	70	70	70	70	70	100
Fuel Design	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Heat Rejection	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers	Wet Cooling Towers
NO_x Control	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR	DLN/SCR
CO Control	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst	Oxidation Catalyst
Particulate Control	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice	Good Combustion Practice
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	4	4	4	4	4	4
ESTIMATED PERFORMANCE (See note 1)						
Base Load Performance @59 °F (Nominal)						
Net Plant Output, kW	363,100	360,800	430,700	427,800	551,200	1,101,400
Net Plant Heat Rate, Btu/kWh (HHV)	6,540	6,590	6,200	6,240	6,270	6,280
Heat Input, MMBtu/h (HHV)	2,370	2,380	2,670	2,670	3,460	6,920
Incremental Duct Fired Performance @ 59 °F (Nominal)						
Incremental Duct Fired Output, kW	N/A	57,700	N/A	80,400	N/A	205,400
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,730	N/A	8,720	N/A	8,690
Incremental Heat Input, MMBtu/h (HHV)	N/A	500	N/A	700	N/A	1,780
Minimum Load (Single Turbine at MECL) @ 59 °F (Nominal)						
Net Plant Output, kW	172,100	171,100	150,000	149,100	202,100	202,100
Net Plant Heat Rate, Btu/kWh (HHV)	7,930	7,970	7,790	7,830	7,520	7,520
Heat Input, MMBtu/h (HHV)	1,360	1,360	1,170	1,170	1,520	1,520
Base Load Performance @ 20 °F (Winter)						
Net Plant Output, kW	364,400	362,000	434,800	431,800	557,300	1,113,700
Net Plant Heat Rate, Btu/kWh (HHV)	6,480	6,530	6,220	6,270	6,280	6,290
Heat Input, MMBtu/h (HHV)	2,360	2,360	2,700	2,710	3,500	7,010
Incremental Duct Fired Performance @ 20 °F (Winter)						
Incremental Duct Fired Output, kW	N/A	57,200	N/A	76,400	N/A	195,100
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,710	N/A	8,720	N/A	8,700
Incremental Heat Input, MMBtu/h (HHV)	N/A	500	N/A	670	N/A	1,700
Minimum Load (Single Turbine at MECL) @ 20 °F (Winter)						
Net Plant Output, kW	173,200	172,100	151,900	151,000	205,200	204,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,050	8,100	8,070	8,120	7,770	7,810
Heat Input, MMBtu/h (HHV)	1,390	1,390	1,230	1,230	1,590	1,590
Base Load Performance @ 90 °F (Summer)						
Net Plant Output, kW	341,200	339,000	421,000	418,300	535,400	1,070,100
Net Plant Heat Rate, Btu/kWh (HHV)	6,530	6,570	6,100	6,140	6,290	6,290
Heat Input, MMBtu/h (HHV)	2,230	2,230	2,570	2,570	3,370	6,730
Incremental Duct Fired Performance @ 90 °F (Summer)						
Incremental Duct Fired Output, kW	N/A	63,000	N/A	84,200	N/A	218,300
Incremental Heat Rate, Btu/kWh (HHV)	N/A	8,720	N/A	8,720	N/A	8,700
Incremental Heat Input, MMBtu/h (HHV)	N/A	550	N/A	730	N/A	1,900
Minimum Load (Single Turbine at MECL) @ 90 °F (Summer)						
Net Plant Output, kW	162,300	161,400	149,800	149,000	200,500	200,500
Net Plant Heat Rate, Btu/kWh (HHV)	8,000	8,050	7,650	7,690	7,450	7,450
Heat Input, MMBtu/h (HHV)	1,300	1,300	1,150	1,150	1,490	1,490
ESTIMATED CAPITAL AND O&M COSTS						
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$460**	**$478**	**$501**	**$530**	**$538**	**$916**
Owner's Costs, 2022 MM$	**$66**	**$67**	**$69**	**$70**	**$70**	**$95**
Owner's Project Development	$3.5	$3.5	$3.5	$3.5	$3.5	$3.5
Owner's Operational Personnel Prior to COD	$1.7	$1.7	$1.7	$1.7	$1.7	$1.9
Owner's Engineer	$2.3	$2.3	$2.3	$2.3	$2.3	$2.6
Owner's Project Management	$5.9	$5.9	$5.9	$5.9	$5.9	$6.8
Owner's Legal Costs	$1.0	$1.0	$1.0	$1.0	$1.0	$1.0
Owner's Start-up Engineering and Commissioning	$5.7	$5.7	$5.7	$5.7	$5.7	$8.4
Land	$0.4	$0.4	$0.4	$0.4	$0.4	$0.6
Temporary Utilities	$1.6	$1.6	$1.6	$1.6	$1.6	$1.7
Permitting and Licensing Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COMBINED CYCLE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	1x1 F Class CCGT - Unfired	1x1 F Class CCGT - Fired	1x1 G/H Class CCGT - Unfired	1x1 G/H Class CCGT - Fired	1x1 J Class CCGT - Unfired	2x1 J Class CCGT - Fired
BASE PLANT DESCRIPTION	Unfired	Fired	Unfired	Fired	Unfired	Fired
Switchyard	$9.8	$9.8	$10.8	$10.8	$10.8	$13.5
Political Concessions & Area Development Fees	$0.5	$0.5	$0.5	$0.5	$0.5	$0.5
Startup/Testing (Fuel & Consumables)	$0.9	$0.9	$0.9	$0.9	$0.9	$1.8
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Site Security	$0.8	$0.8	$0.8	$0.8	$0.8	$0.8
Operating Spare Parts	$6.0	$6.0	$6.0	$6.0	$6.0	$7.2
Permanent Plant Equipment and Furnishings	$1.3	$1.3	$1.3	$1.3	$1.3	$1.3
Builders Risk Insurance (0.45% of Construction Costs)	$1.8	$1.9	$1.9	$2.1	$2.1	$3.3
Owner's Contingency	$22.1	$22.8	$23.8	$25.1	$25.3	$39.9
Total Project Costs, 2022 MM$	**$526**	**$545**	**$570**	**$600**	**$608**	**$1,012**
Total Project Costs, 2022 MM$ W AFUDC	**$617**	**$639**	**$668**	**$703**	**$713**	**$1,187**
EPC Cost Per UNFIRED kW, 2022 $/kW	**$1,270**	**$1,330**	**$1,160**	**$1,240**	**$980**	**$830**
Total Cost Per UNFIRED kW, 2022 $/kW	**$1,450**	**$1,510**	**$1,320**	**$1,400**	**$1,100**	**$920**
EPC Cost Per FIRED kW, 2022 $/kW	**N/A**	**$1,140**	**N/A**	**$1,040**	**N/A**	**$700**
Total Cost Per FIRED kW, 2022 $/kW	**N/A**	**$1,300**	**N/A**	**$1,180**	**N/A**	**$770**
FIXED O&M COSTS (See note 9)						
Fixed O&M Cost - LABOR, 2022 $MM/Yr	$2.8	$2.8	$2.8	$2.8	$2.8	$3.2
Fixed O&M Cost - OTHER, 2022 $MM/Yr	$1.7	$1.7	$1.7	$1.7	$1.7	$2.0
LEVELIZED CAPITAL MAINTENANCE COSTS						
Major Maintenance Cost, 2022 $/GT-hr	$350	$350	$500	$500	$600	$600
Major Maintenance Cost, 2022 $/MWh	$1.00	$1.00	$1.20	$1.20	$1.10	$1.10
Catalyst Replacement Cost, 2022 $/MWh	$0.20	$0.20	$0.20	$0.20	$0.10	$0.10
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)						
Total Variable O&M Cost, Unfired 2022 $/MWh	$1.60	$1.60	$1.60	$1.60	$1.50	$1.40
Water Related O&M ($/MWh)	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
SCR Reagent, $/MWh	$0.20	$0.20	$0.20	$0.20	$0.20	$0.20
Other Consumables and Variable O&M ($/MWh)	$1.20	$1.20	$1.20	$1.20	$1.10	$1.00
Incremental Duct Fired Variable O&M, 2022 $/MWh (For Incremental Output Only)	N/A	$1.30	N/A	$1.20	N/A	$1.20
CARBON CAPTURE ADD-ON COST						
Carbon Capture Solvlent Based Technology Capital Costs, 2022 MM$	N/A	N/A	$560	N/A	N/A	N/A
Carbon Compression, Transportation, and Sequestration Capital Costs, 2021 MM$	N/A	N/A	$160	N/A	N/A	N/A
Owner's Costs, 2022 MM$	N/A	N/A	$39	N/A	N/A	N/A
CARBON CAPTURE O&M COSTS						
Incremental Fixed O&M Cost, 2022 MM$/Yr	N/A	N/A	$16	N/A	N/A	N/A
Incremental Variable O&M Cost, 2022$/MWh	N/A	N/A	$4	N/A	N/A	N/A
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV)						
NO_x	0.007	0.007	0.007	0.007	0.007	0.007
SO_2	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002	< 0.002
CO	0.004	0.004	0.004	0.004	0.004	0.004
CO_2	120	120	120	120	120	120

Notes

Note 1: New and clean performance assumed. All performance is based on NATURAL GAS operation. Min load ratings are based on OEM performance information at specified ambient conditions.
Note 2: Base O&M costs are based on performance at annual average conditions.
Note 3: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. When average hours per start over the interval are <27, then major maintenance costs would be starts based.
Note 4: MECL start time assumes the time for the GT to emissions compliance load (not stack compliance). The SCR compliance start time assumes a cold start, ending at the time when the catalysts are heated and the NOx levels meet the desired stack emissions.
Note 5: Options with duct firing include a design of firing up to 1,600°F.
Note 6: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle data is based on North American units that came online in 2006 or later. Reporting period is 2011-2016.
Note 7: For the purpose of startup times, a Cold start is defined as being shutdown for >72 hours. A Hot start is defined as shutdown for <8 hours.
Note 8: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of terminal point desuperheaters, full bypass, and associated controls. Fast start packages are not included in CCGT plants.
Note 9: Fixed O&M assumes 22 FTE for 1x1 configurations.
Note 10: Variable O&M costs assume onsite demin treatment system.
Note 11: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts.
Note 12: Estimated costs exclude decommissioning costs and salvage values.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Supercritical Pulverized Coal with Carbon Capture	Ultra-Supercritical Pulverized Coal with Carbon Capture
BASE PLANT DESCRIPTION		
Nominal Output	500 MW Net with CCS	750 MW Net with CCS
Number of Gas Turbines	N/A	N/A
Number of Boilers/Reactors	1	1
Number of Steam Turbines	1	1
Steam Conditions (Main Steam / Reheat)	1050 F/1050F	1100 F/1100F
Main Steam Pressure	3675 psia	3694 psia
Steam Cycle Type	Supercritical	Ultra-Supercritical
Capacity Factor (%)	70%	70%
Startup Time (Cold Start)	10 Hours	10 Hours
Startup Time (Warm Start)	6 Hours	6 Hours
Startup Time (Hot Start)	4 Hours	4 Hours
Book Life (Years)	33	33
Equivalent Planned Outage Rate (%)	9.0%	8.8%
Equivalent Forced Outage Rate (%)	10.9%	8.8%
Equivalent Availability Factor (%)	79.5%	80.8%
Fuel Design	Bituminous Coal	Bituminous Coal
Heat Rejection	Wet Cooling Tower	Wet Cooling Tower
NO_x Control	Low NOx burners / SCR	Low NOx burners / SCR
SO_2 Control	Integrated WFGD and DFGD	Integrated WFGD and DFGD
Acid Gas Control	Integrated WFGD and DFGD	Integrated WFGD and DFGD
CO_2 Control	Advanced Amine	Advanced Amine
Particulate Control	Baghouse	Baghouse
Ash Disposal	Landfill	Landfill
Technology Rating	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	6.5	6.5
ESTIMATED PERFORMANCE		
Base Load Performance @ (Annual Average) w/ Carbon Capture		
Net Plant Output, kW	505,750	747,100
Net Plant Heat Rate, Btu/kWh (HHV)	11,290	10,480
Heat Input, MMBtu/h (HHV)	5,710	7,830
Minimum Load Operational Status @ (Annual Average)		
Net Plant Output, kW	177,010	298,840
Net Plant Heat Rate, Btu/kWh (HHV)	13,410	12,240
Heat Input, MMBtu/h (HHV)	2,370	3,660
ESTIMATED CAPITAL AND O&M COSTS		
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$3,067**	**$4,142**
Owner's Costs, 2022 MM$	**$300**	**$359**
Owner's Project Development	$7.5	$7.5
Owner's Operational Personnel Prior to COD	$7.7	$7.7
Owner's Engineer	$11.5	$11.5
Owner's Project Management	$10.0	$10.0
Owner's Legal Costs	$3.0	$3.0
Owner's Start-up Engineering	$0.4	$0.4
Land	$5.0	$5.0
Operator Training	$0.6	$0.6
Construction Power and Water	$3.6	$3.6
Permitting and Licensing Fees	$4.0	$4.0

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
COAL TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	**Supercritical Pulverized Coal with Carbon Capture**	**Ultra-Supercritical Pulverized Coal with Carbon Capture**
BASE PLANT DESCRIPTION		
Switchyard	$10.1	$10.1
Political Concessions & Area Development Fees	$2.5	$2.5
Startup/Testing (Fuel & Consumables)	$30.1	$30.1
Initial Fuel Inventory	$16.8	$16.8
Site Security	$0.6	$0.6
Operating Spare Parts	$8.2	$8.2
Permanent Plant Equipment and Furnishings	$4.6	$4.6
Builders Risk Insurance (0.45% of Construction Costs)	$13.8	$18.6
Owner's Contingency (5% for Screening Purposes)	$160	$214
Total Project Costs, 2019 MM$	**$3,368**	**$4,501**
Total Project Costs, 2022 MM$ W AFUDC	**$4,390**	**$5,867**
EPC Cost Per kW, 2019 $/kW	**$6,065**	**$5,544**
Total Cost Per kW, 2019 $/kW	**$6,660**	**$6,020**
CO_2 Transportation and Geologic Sequestration (See note 4)		
50 Mile Pipeline Cost, 2022 MM$	$144	$168
CO_2 Pipeline Maintenance ($/MWh)	$4.05	$4.05
CO_2 Storage Cost ($/MWh)	$9.14	$9.14
Fixed O&M Cost, 2022$/kW-Yr	$32.01	$32.01
Fixed O&M Cost, 2022 $MM/Yr	$16.20	$23.90
Major Maintenance Cost, 2022$/MWh	$5.72	$5.72
Variable O&M Cost, 2022$/MWh (excl. major maint.)	$14.85	$14.85
ESTIMATED BASE LOAD OPERATING EMISSIONS (NO CCS), lb/MMBtu (HHV)		
NO_X	0.02	0.02
SO_2	0.02	0.02
CO	0.15	0.15
CO_2	100	100

Notes
Note 1: PC cost and performance are based on net performance inclusive of carbon capture.
Note 2: The PC unit assumes that cooler tower blowdown is recycled in the FGD.
Note 3: The PC unit assumes a spray dry absorber will be used to control acid gases. FGD purge will be recycled in the SDA.
Note 4: Carbon transportation and sequestration assumes 50 mile pipeline to a suitable subterranean reservoir.
Note 5: Outage and availability statistics are collected using the NERC Generating Availability Data System. Reporting period is those units that report

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
MIDWEST
AUGUST 2022

PROJECT TYPE	**Nuclear**	
BASE PLANT DESCRIPTION	Small Modular Reactor	
Representative Technology	NuScale technology configuration	
Number of Modules	First Module	Next Module
Number of Steam Turbines	1	1
Capacity Factor (%)	95%	95%
Startup Time, Minutes (Cold Start to Unfired Base Load)	96 Minutes (20% to 100%)	96 Minutes (20% to 100%)
Maximum Ramp Rate, %/min	~1%/min or 40%/hr	~1%/min or 40%/hr
Scheduled Outage Factor (SOF), %	2%	2%
Forced Outage Factor (FOF), %	5%	5%
Availability Factor (AF), %	95%	95%
Book Life (Years)	60	60
Fuel Design	≤ 5% Enriched Uranium	≤ 5% Enriched Uranium
Heat Rejection	Dry Cooling	Dry Cooling
Technology Rating	Developing	Developing
Permitting & Construction Schedule (Years from FNTP)	6	6
ESTIMATED PERFORMANCE		
Base Load Performance @ (Annual Average)		
Gross Plant Output, kW	77,000	77,000
Net Plant Output, kW	73,700	73,700
Net Plant Heat Rate, Btu/kWh (HHV)	11,580	11,580
ESTIMATED CAPITAL AND O&M COSTS		
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs) (Note 1)	**$580**	**$570**
Civil/Structural/Architectural	Included in Project Cost	Included in Project Cost
Mechanical	Included in Project Cost	Included in Project Cost
Electrical	Included in Project Cost	Included in Project Cost
Indirects and Fees	Included in Project Cost	Included in Project Cost
Owner's Costs, 2022 MM$ (Note 2)		
Owner's Contingency (Note 6)	$116	$114
Total Project Costs, 2022 MM$	**$696**	**$684**
Total Project Costs, 2022 MM$ W AFUDC	**$888**	**$873**
EPC Cost Per kW, 2022 $/kW	**$7,870**	**$7,734**
Total Cost Per kW, 2022 $/kW	**$9,444**	**$9,281**
Fixed O&M Cost - TOTAL, 2022$MM/Yr (Note 3)	$106	$106
Variable O&M Cost, 2019$/MWh (Note 4)	$0.7	$0.7

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
NUCLEAR TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
MIDWEST
AUGUST 2022

PROJECT TYPE	**Nuclear**	
BASE PLANT DESCRIPTION	Small Modular Reactor	
CASH FLOW PATTERNS (Note 5)		
Total Plant Construction Cost		
Year 1	N/A	N/A
Year 2	N/A	N/A
Year 3	N/A	N/A

Notes
Note 1: Costs based on EPC contracting approach from publically available data produced by NREL. Direct costs include equipment, material, and labor to construct the civil/structural, mechanical, a
Note 2: Owner's costs include project development, studies, permitting, legal, owner's project management, owner's engineering, and owner's startup and commissioning costs. Other owner's costs i
Note 3: Fixed O&M costs include labor, materials and contracted services, and G&A costs. O&M costs exclude property taxes and insurance.
Note 4: Variable O&M costs include water, water discharge treatment cost, chemicals, and consumables. Fuel is not included.
Note 5: Due to the technology rating for this option, yearly cash flows are unavailable at this time
Note 6: Owner's contingency recommendation is elevated for this technology option to 20% as opposed to the 5% used for other technologies based on historical risks to nuclear technology product c
Note 7: Performance data based on NuScale press releases (NuScale Year in Review 2020, Accessed March 30, 2022).

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Reciprocating Engine (9 MW Engines) Natural Gas		Reciprocating Engine (18 MW Engines) Natural Gas	
BASE PLANT DESCRIPTION	First Unit	Next Unit	First Unit	Next Unit
Number of Gas Turbines/Engines/Units	6	6	6	6
Representative Class Gas Turbine	Wartsila 20V34SG		Wartsila 18V50SG	
Capacity Factor, %	Peaking (10%)		Peaking (10%)	
Startup Time to Base Load, min (Notes 1)	5		5	
Startup Time to MECL, min	4		4	
Cold Startup Time to SCR Compliance, min	45		45	
Maximum Ramp Rate, MW/min (Online)	55		110	
Book Life, Years	35		35	
Equivalent Planned Outage Rate, % (Note 2)	3.5%		3.5%	
Equivalent Forced Outage Rate, % (Notes 2)	4.3%		4.3%	
Equivalent Availability Factor, % (Notes 2)	92.2%		92.2%	
Assumed Land Use, Acres	30	10	30	10
Fuel Design	Natural Gas Only		Natural Gas Only	
Heat Rejection	Fin Fan Heat Exchanger		Fin Fan Heat Exchanger	
NO_x Control	SCR		SCR	
CO Control	Oxidation Catalyst		Oxidation Catalyst	
Particulate Control	Good Combustion Practice		Good Combustion Practice	
Technology Rating	Mature		Mature	
Permitting & Construction Schedule (Years from FNTP)	3	3	3	3
ESTIMATED PERFORMANCE (All BASED ON NATURAL GAS OPERATION) (Note 3)				
Nominal Base Load Performance @59° F (ISO Conditions)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,440	8,440	8,360	8,360
Heat Input, MMBtu/h (HHV)	460	460	920	920
Nominal Min Load @ 59° F (ISO Conditions) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
Base Load Performance @ 20° F (Winter Design)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,440	8,440	8,360	8,360
Heat Input, MMBtu/h (HHV)	460	460	920	920
Min Load Operational Status @ 20° F (Winter Design) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
Base Load Performance @ 90° F (Summer Design)				
Net Plant Output, kW	54,500	54,500	110,100	110,100
Net Plant Heat Rate, Btu/kWh (HHV)	8,620	8,620	8,360	8,360
Heat Input, MMBtu/h (HHV)	470	470	920	920
Min Load Operational Status @ 90° F (Summer Design) - Single Engine				
Net Plant Output, kW	3,600	3,600	7,300	7,300
Net Plant Heat Rate, Btu/kWh (HHV)	11,110	11,110	9,590	9,590
Heat Input, MMBtu/h (HHV)	40	40	70	70
ESTIMATED CAPITAL AND O&M COSTS				
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$79**	**$58**	**$150**	**$114**
Engineering	$4.0	$1.2	$6	$1
Gas Turbines/Engines	$30.0	$27.0	$58	$55
GSU (Note 4)	$1.1	$1.1	$2	$2
Environmental Equipment (SCR/CO)	Included	Included	Included	Included
BOP Equipment and Materials	$6.8	$5.1	$23	$18
Construction	$22.3	$13.4	$33	$20
Indirects and Fees	$11.0	$7.3	$22	$15
EPC Contingency	$3.6	$2.6	$7	$5
Owner's Costs, 2022 MM$	**$17**	**$6**	**$22**	**$11**
Owner's Project Development	$0.3	$0.0	$0.3	$0.0
Owner's Operational Personnel Prior to COD	$0.3	$0.0	$0.3	$0.0
Owner's Engineer	$0.8	$0.0	$0.5	$0.0
Owner's Project Management	$1.0	$0.0	$1.0	$0.0

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RECIPROCATING ENGINE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Reciprocating Engine (9 MW Engines) Natural Gas		Reciprocating Engine (18 MW Engines) Natural Gas	
Owner's Legal Costs	$0.5	$0.0	$0.5	$0.0
Owner's Start-up Engineering and Commissioning	$0.5	$0.2	$0.9	$0.5
Land	$0.2	$0.0	$0.2	$0.1
Construction Power and Water	$0.5	$0.1	$0.5	$0.1
Permitting and Licensing Fees	$0.5	$0.0	$0.5	$0.0
Switchyard	$5.3	$1.8	$7.1	$3.5
Political Concessions & Area Development Fees	$0.5	$0.0	$0.5	$0.0
Startup/Testing (Fuel & Consumables)	$0.2	$0.1	$0.0	$0.0
Initial Fuel Inventory	$0.0	$0.0	$0.0	$0.0
Site Security	$0.4	$0.0	$0.4	$0.0
Operating Spare Parts	$0.4	$0.1	$0.3	$0.0
Permanent Plant Equipment and Furnishings	$0.3	$0.0	$0.0	$0.0
Builders Risk Insurance (0.45% of Construction Costs)	$0.4	$0.3	$0.7	$0.5
Owner's Contingency (5% for Screening Purposes)	$4.6	$3.0	$8.2	$5.9
Total Project Costs, 2022 MM$	**$96**	**$64**	**$172**	**$125**
Total Project Costs, 2022 MM$ W AFUDC	**$108**	**$72**	**$193**	**$140**
EPC Cost Per kW, 2022 $/kW	**$1,450**	**$1,064**	**$1,362**	**$1,035**
Total Cost Per kW, 2022 $/kW	**$1,756**	**$1,167**	**$1,561**	**$1,132**
FIXED O&M COSTS				
Fixed O&M Cost - LABOR, 2022$MM/Yr	$1.0	$0.4	$1.0	$0.4
Fixed O&M Cost - OTHER, 2022$MM/Yr	$0.5	$0.2	$1.0	$0.4
LEVELIZED CAPITAL MAINTENANCE COSTS				
Major Maintenance Cost, 2022$/GT-hr or $/engine-hr (Notes 6)	$10.80	$10.80	$20.00	$20.00
Major Maintenance Cost, 2022$/GT-start	N/A	N/A	N/A	N/A
Major Maintenance Cost, 2022$/MWh	$1.20	$1.20	$1.10	$1.10
Catalyst Replacement Cost, 2022$/MWh	$0.30	$0.30	$0.10	$0.10
NON-FUEL VARIABLE O&M COSTS (EXCLUDES MAJOR MAINTENANCE)				
Total Variable O&M Cost, 2022$/MWh	$5.60	$5.60	$4.50	$4.50
Water Related O&M, $/MWh	$0.00	$0.00	$0.00	$0.00
SCR Reagent, $/MWh	$0.90	$0.90	$0.90	$0.90
Other Consumables and Variable O&M, $/MWh	$4.70	$4.70	$3.60	$3.60
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS (See Note 8)				
Engine Only (lb/MMBtu, HHV)	N/A	N/A	N/A	N/A
NO_X	N/A	N/A	N/A	N/A
SO_2	N/A	N/A	N/A	N/A
CO	N/A	N/A	N/A	N/A
CO_2				
Engine with SCR and CO Catalyst (lb/MMBtu, HHV)				
NO_X	0.021	0.021	0.021	0.021
SO_2	< 0.002	< 0.002	< 0.002	< 0.002
CO	0.031	0.031	0.032	0.032
CO_2	120	120	120	120

Notes

Note 1: Recip engine start times assume the engines are kept warm when not operational.
Note 2: Outage and availability statistics are collected using the NERC Generating Availability Data System. Note that a unique gas reciprocating engine category does not exist in GADS. Diesel Engine data is used as a proxy.
Note 3: New and clean performance assumed for all scenarios. All performance ratings based on NATURAL GAS operation. Minimum loads are based on OEM information at requested ambient conditions.
Note 4: It is assumed that a maximum of six reciprocating engines tie to one GSU.
Note 5: Capital and fixed O&M costs are presented in 2022 USD $MM.
Note 6: Recip engine FOM assumes 8 FTE for the first 200 MW plant. Major maintenance $/hr is per engine. LTSA costs are split in two categories: major overhauls and catalyst replacements are shown
Note 7: Not Used.
Note 8: Emissions estimates are shown for steady state operation at annual average conditions. Estimates account for the impacts of SCR and CO catalysts, as applicable.
Note 9: Performance ratings are based on elevation of 120 ft above msl.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Wind Energy	Wind Energy	Wind Plus Storage	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic	Solar Plus Storage
BASE PLANT DESCRIPTION	Southern IN	Northern IN	Indiana	Single Axis Tracking	Single Axis Tracking	Single Axis Tracking	Single Axis Tracking
Nominal Output, MW	200	200	50 MW Wind & 10 MW / 40 MWh Storage	10	50	100	50 MW PV & 10 MW / 40 MWh Storage
Number of Turbines	53 x 3.8 MW	53 x 3.8 MW	14 x 3.8 MW	N/A	N/A	N/A	N/A
Capacity Factor (%) (Notes 1,2)	28.1%	38.3%	38.3%	25.2%	25.2%	25.2%	25.2%
Book Life (Years)	30	30	30 Wind / 20 BESS	30	30	30	30 Wind / 20 BESS
Scheduled Outage Factor (SOF), % (Note 5)	< 5%	< 5%	< 5%	<1%	<1%	<1%	<1%
Forced Outage Factor (FOF), % (Note 5)	< 5%	< 5%	< 5%	<1%	<1%	<1%	<1%
Availability Factor (AF), % (Note 5)	95%	95%	95%	99%	99%	99%	99%
Assumed Land Use (Acres)	53	53	16	70	350	700	352
Interconnection Voltage Assumption	230 kV	230 kV	230 kV	115 kV	115 kV	230 kV	115 kV
PV Inverter Loading Ratio (DC/AC)	N/A	N/A	N/A	1.35	1.35	1.35	1.35
PV Degradation (%/yr) (Note 6)	N/A	N/A	N/A	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%	First year: 2% After 1st Year: 0.5%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Permitting & Construction Schedule (Years from FNTP)	2.5	2.5	2.5	2	2	2	2
ESTIMATED PERFORMANCE							
Base Load Performance @ (Annual Average) Net Plant Output, kW	200,000	200,000	50,000	10,000	50,000	100,000	50,000
ESTIMATED CAPITAL AND O&M COSTS							
Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$320**	**$320**	**$108**	**$22**	**$86**	**$159**	**$106**
Wind Capital Cost Breakdown							
Engineering	**$11.5**	**$11.5**	**$3.2**	**N/A**	**N/A**	**N/A**	**N/A**
Equipment and Materials	$215	$215	$59	N/A	N/A	N/A	N/A
Turbine Towers	Included	Included	Included	N/A	N/A	N/A	N/A
Turbine Blades	Included	Included	Included	N/A	N/A	N/A	N/A
Turbine Hubs	Included	Included	Included	N/A	N/A	N/A	N/A
Nacelle and nacelle components	Included	Included	Included	N/A	N/A	N/A	N/A
SCADA Equipment	Included	Included	Included	N/A	N/A	N/A	N/A
Construction	$93	$93	$26	N/A	N/A	N/A	N/A
Turbine Foundation and Erection	Included	Included	Included	N/A	N/A	N/A	N/A
BOP Costs	Included	Included	Included	N/A	N/A	N/A	N/A
Collector Bus	Included	Included	Included	N/A	N/A	N/A	N/A
Indirects and Fees	Included	Included	Included	N/A	N/A	N/A	N/A
EPC Contingency	Included	Included	Included	N/A	N/A	N/A	N/A
PV Capital Cost Breakdown							
Engineering	N/A	N/A	N/A	$1	$1	$2	$1.0
Equipment and Materials	N/A	N/A	N/A	$10	$38	$79	$38.0
Modules	N/A	N/A	N/A	$7	$27	$55	$27.0
Inverters	N/A	N/A	N/A	$1	$2	$5	$2.0
Racking	N/A	N/A	N/A	$2	$9	$19	$9.0
Construction	N/A	N/A	N/A	$8	$35	$60	$35.0
Indirects and Fees	N/A	N/A	N/A	$2	$8	$11	$8.0
EPC Contingency	N/A	N/A	N/A	$1	$4	$7	$4.0
Battery Storage Capital Cost Breakdown			**$20**				**$20**
Batteries	N/A	N/A	$12	N/A	N/A	N/A	$12
Inverters	N/A	N/A	$1	N/A	N/A	N/A	$1
BOP	N/A	N/A	$1	N/A	N/A	N/A	$1
Construction and Indirects	N/A	N/A	$6	N/A	N/A	N/A	$6
Owner's Costs, 2022 MM$	**$48.9**	**$48.9**	**$18**	**$3.6**	**$6.8**	**$18.9**	**$9**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Allowance Included	Allowance Included	Included in EPC	Included in EPC	Included in EPC	Included in EPC	Included in EPC
Land (Note 8)	Excluded	Excluded	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Permitting and Licensing Fees	Allowance Included	Allowance Included	Included in EPC	Included in EPC	Included in EPC	Included in EPC	Included in EPC
Switchyard / Substation (Notes 7,9)	$5.2 M Allowance Included	$5.2 M Allowance Included	$6.2 M Allowance Included	$1.0M Allowance Included	$1.0M Allowance Included	$5.2 M Allowance Included	$2.0M Allowance Included
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2022 MM$	**$369**	**$369**	**$126**	**$26**	**$93**	**$178**	**$115**
Total Project Costs, 2022 MM$ W AFUDC	**$407**	**$407**	**$139**	**$28**	**$100**	**$192**	**$124**
Fixed O&M Cost - TOTAL, 2022$MM/Yr (Notes 3,4)	**$9.6**	**$9.6**	**$2.9**	**$0.6**	**$0.8**	**$1.1**	**$1.1**
Annual Fixed Labor Cost, 2022$MM/Yr	Allowance Included	Allowance Included	Allowance Included	$0.0	$0.0	$0.0	$0.0
Equipment Maintenance Cost, 2022$MM/Yr	Allowance Included	Allowance Included	$0.3	$0.5	$0.5	$0.5	$0.8
BOP and Other Cost, 2022$MM/Yr	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Land Lease Allowance, 2022$MM/Yr (Notes 8)	Allowance Included	Allowance Included	Allowance Included	Excluded	Excluded	Excluded	Excluded
Property Tax Allowance, 2022$MM/Yr	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded	Excluded
Capital Replacement Allowance, 2022$/MWh (Notes 3-4)	20% of FOM	20% of FOM	20% of FOM	$0.1	$0.2	$0.5	$0.1
Variable O&M Cost, 2022$/MWh (excl. major maint.) (Note 4)	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**	**Included in FOM**

Note 1: Wind capacity factor represents Net Capacity Factor (NCF), which accounts for typical system losses. Capacity factor is based on General Electric 3.8 MW turbines (GE3.8-137) with 110 meter hub height and 8.0 m/s average wind speed.
Note 2: Solar capacity factor accounts for typical losses. Inverter loading ratios assumed as 1.35. Assumes no inverter overbuild at the POI, 35% Ground Coverage Ratio and bifacial modules.
Note 3: Capital maintenance allowances for onshore wind options are not included in the annual FOM above. A supplemental table in the report shows capital allowances estimated as percentages of annual operating expenses for a 30 year life.
Note 4: PV O&M estimates assume fixed contracts for all maintenance activities. It is assumed the system is remotely controlled. Capital maintenance assumes an inverter replacement allowance levelized over the first 15 years.
Note 5: NERC GADS performance statistics are not available for PV and wind technologies. Availability estimates are based on vendor correspondence and industry publications.
Note 6: PV degradation based on typical warranty information for polycrystalline products. Assuming factory recommended maintenance is performed, PV performance is estimated to degrade ~2% in the first year and 0.5% each remaining year.
Note 7: EPC costs for wind include 34.5 kV collection system and GSU to 230 kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV. Owner's costs include 3 position ring bus switchyard for interconnection at 230kV.
Note 8: Onshore wind and PV projects assume that land is leased and therefore land costs are included in O&M, not capital costs. Onshore wind assumes one acre per turbine. PV seven acres per MW for tracking options.
Note 9: PV scope for EPC includes 34.5 kV collection system and GSU. Owner costs include allowance for interconnection at 115 kV including a new 115 kV 3 position ring bus.
Note 10: Note Used
Note 11: Estimated Costs exclude decommisioning costs and salvage values.
Note 12: Sites are assumed to be regularly shaped and designed to allow for CAB BLA and requires minimal vegetation control. Soils, flood hazards, and geotechnical conditions are also assumed to be conducive for cost minimization.
Note 13: Not Used.
Note 14: PV 20% spend in Year 1 is based on 5 month LNTP prior to FNTP spend.

CENTERPOINT 2022 IRP TECHNOLOGY ASSESSMENT
RENEWABLE AND STORAGE TECHNOLOGY ASSESSMENT PROJECT OPTIONS
PRELIMINARY - NOT FOR CONSTRUCTION
AUGUST 2022

PROJECT TYPE	Battery Storage	Battery Storage	Battery Storage	Long Duration Storage
BASE PLANT DESCRIPTION	Lithium Ion	Lithium Ion	Lithium Ion	CAES
Nominal Output, MW	10 MW / 40 MWh	50 MW / 200 MWh	100 MW / 400 MWh	300 MW / 3,000 MWh
Capacity Factor (%)	16.3%	16.3%	16.3%	37.5%
Use Case Assumption	1 discharge/day	1 discharge/day	1 discharge/day	0.5 discharge/day
Book Life (Years)	20	20	20	35
Equivalent Planned Outage Rate (%)	< 2%	< 2%	< 2%	3%
Equivalent Forced Outage Rate (%)	< 2%	< 2%	< 2%	2%
Equivalent Availability Factor (%)	98%	98%	98%	95%
Assumed Land Use (Acres)	3	6	9	43
Heat Rejection	Air Cooled HVAC	Air Cooled HVAC	Air Cooled HVAC	Process Thermal Storage
Total System Cycles	7,300	7,300	7,300	5,300
Interconnection Voltage Assumption	115 kV	230 kV	230 kV	230 kV
Storage System AC Capacity at POI (MWh)	40	200	400	0%
Storage System AC Capacity Installed (MWh)	48	240	480	0%
Storage System Degradation (%/yr)	2%	2%	2%	0%
Storage System AC Roundtrip Efficiency (%)	85%	85%	85%	60%
Technology Rating	Mature	Mature	Mature	Developing
Permitting & Construction Schedule (Years from FNTP)	2	2	2	4.5
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	10,000	50,000	100,000	300,000
ESTIMATED CAPITAL AND O&M COSTS				
Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	**$20**	**$89**	**$173**	**$660**
Battery Storage Capital Cost Breakdown				
Batteries (Assumes Owner Procurement of Battery Integrator Scope)	$12	$64	$122	N/A
Inverters	$1	$3	$5	N/A
BOP	$1	$4	$5	N/A
Construction and Indirects	$6	$18	$41	N/A
Long-Term Storage Capital Cost Breakdown				
Topside	N/A	N/A	N/A	$400
Subsurface	N/A	N/A	N/A	$260
Owner's Costs, 2022 MM$	**$5**	**$19**	**$29**	**$117**
Owner's Project Development	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Engineer	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Project Management	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Startup / Testing / Warranties	Inlcuded in Project Cost	Inlcuded in Project Cost	Inlcuded in Project Cost	Allowance Included
Land	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease	Excluded - Assumes Lease
Permitting and Licensing Fees	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Switchyard / Substation	$1.0	$5.2	$5.2	Allowance Included
Builder's Risk Insurance	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Owner's Contingency	Allowance Included	Allowance Included	Allowance Included	Allowance Included
Total Project Costs, 2022 MM$	**$25**	**$108**	**$202**	**$777**
Total Project Costs, 2022 MM$ W AFUDC	**$27**	**$117**	**$218**	**$931**
Fixed O&M Cost - TOTAL, 2022$MM/Yr	**$0.4**	**$1.9**	**$3.5**	**$5.8**
Annual Fixed Labor Cost, 2022$MM/Yr	$0	$0	$0	Allowance Included
Equipment Maintenance Cost, 2022$MM/Yr	$0.3	$1.7	$3.2	Allowance Included
BOP and Other Cost, 2022$MM/Yr	Included in FOM	Included in FOM	Included in FOM	Allowance Included
Land Lease Allowance, 2022$MM/Yr (Notes 4)	Excluded	Excluded	Excluded	$0.03
Property Tax Allowance, 2022$MM/Yr	Excluded	Excluded	Excluded	$0.0004
Capital Replacement Allowance, 2022$/MWh (Notes 2)	$0.1	$0.2	$0.3	Excluded
Variable O&M Cost, 2022$/MWh (excl. major maint.)	Included in FOM	Included in FOM	Included in FOM	$2.6

Notes

Note 1: Lithium ion capacity factor calculations assume single daily charge and discharge cycles over the year with allowances for equipment expected availability.

Note 2: Battery FOM assumes the site is remotely controlled. A battery replacement fund (augmentation) is included in the FOM to accommodate for degradation throughout the project life. Variable O&M accounts for the parasitic power draw of the system, including HVAC and efficiency losses.

Note 3: NERC GADS performance statistics are not available for battery storage. Availability estimates are based on vendor correspondence and industry publications.

Note 4: Land lease and property estimate allowances are excluded.

Note 5: Estimated Costs exclude decommisioning costs and salvage values.

CENTERPOINT ENERGY 2022 GENERIC UNIT ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TO COMBINED CYCLE CONVERSION TECHNOLOGY ASSESSMENT
PRELIMINARY - NOT FOR CONSTRUCTION
INDIANA
August 2022 - Revision 0

PROJECT TYPE	**2x1 F Class SCGT to CCGT Conversion**
BASE PLANT DESCRIPTION	
Number of Gas Turbines	2
Number of Steam Turbines	1
Representative Class Gas Turbine	GE 7F.05
Steam Conditions (Main Steam / Reheat)	1,050 °F / 1,050 °F
Main Steam Pressure	2,400 psia
Steam Cycle Type	Subcritical
Capacity Factor (%)	70%
Startup Time, Minutes (Cold Start to Unfired Base Load) (Note 1)	180
Startup Time, Minutes (Warm Start to Unfired Base Load) (Note 1)	120
Startup Time, Minutes (Hot Start to Unfired Base Load) (Note 1)	80
Startup Time, Minutes (Cold Start to Stack Emissions Compliance) (Note 2)	60
Maximum Ramp Rate, MW/min (Online)	72
Book Life (Years)	35
Scheduled Outage Factor (SOF), % (Note 3)	10.4%
Forced Outage Factor (FOF), % (Note 3)	1.4%
Availability Factor (AF), % (Note 3)	88.2%
Fuel Design	Natural Gas
Heat Rejection	Wet Cooling Towers
NO_x Control	DLN/SCR
CO Control	Oxidation Catalyst
Particulate Control	Good Combustion
Technology Rating	Mature
Permitting & Construction Schedule (Years from FNTP)	2.50
ESTIMATED PERFORMANCE (Note 4)	
Base Load Performance @ 59 °F (Nominal)	
Net Plant Output, kW	716,900
Net Plant Heat Rate, Btu/kWh (HHV)	6,480
Heat Input, MMBtu/h (HHV)	4,650
Minimum Load (Single Turbine at MECL) @ 59 °F (Nominal)	
Net Plant Output, kW	165,300
Net Plant Heat Rate, Btu/kWh (HHV)	7,920
Heat Input, MMBtu/h (HHV)	1,310
Base Load Performance @ 5 °F (Winter)	
Net Plant Output, kW	719,400
Net Plant Heat Rate, Btu/kWh (HHV)	6,570
Heat Input, MMBtu/h (HHV)	4,730
Minimum Load (Single Turbine at MECL) @ 5 °F (Winter)	
Net Plant Output, kW	170,000
Net Plant Heat Rate, Btu/kWh (HHV)	8,210
Heat Input, MMBtu/h (HHV)	1,400
Base Load Performance @ 90 °F (Summer)	
Net Plant Output, kW	686,300
Net Plant Heat Rate, Btu/kWh (HHV)	6,560
Heat Input, MMBtu/h (HHV)	4,500
Minimum Load (Single Turbine at MECL) @ 90 °F (Summer)	
Net Plant Output, kW	153,800
Net Plant Heat Rate, Btu/kWh (HHV)	8,230
Heat Input, MMBtu/h (HHV)	1,270
ESTIMATED STARTUP FUEL USAGE	
Start to Stack Emissions Compliance, MMBtu	1,720
Start to Unfired Base Load, MMBtu	8,530
ESTIMATED WATER USAGE (Note 6)	
Water Consumption (kgal/yr)	1,451,000
Water Consumption with Evap Cooler (kgal/yr)	1,474,000
ESTIMATED REAGENT USAGE (Note 6)	
Ammonia Consumption (tons/yr)	4,530
ESTIMATED CAPITAL AND O&M COSTS (Note 7)	
EPC Project Capital Costs, 2022 MM$ (w/o Owner's Costs)	[redacted]
Engineering	
Gas Turbines	
HRSGs	
Steam Turbine	
GSUs	
BOP Equipment and Materials	
Construction	
Indirects and Fees	
EPC Contingency	
Owner's Costs, 2022 MM$	

CENTERPOINT ENERGY 2022 GENERIC UNIT ASSESSMENT SUMMARY TABLE
SIMPLE CYCLE TO COMBINED CYCLE CONVERSION TECHNOLOGY ASSESSMENT
PRELIMINARY - NOT FOR CONSTRUCTION
INDIANA
August 2022 - Revision 0

PROJECT TYPE	**2x1 F Class SCGT to CCGT Conversion**
Owner's Project Development	[redacted]
Owner's Operational Personnel Prior to COD	
Owner's Engineer	
Owner's Project Management	
Owner's Legal Costs	
Owner's Start-up Engineering and Commissioning	
Land	
Temporary Utilities	
Permitting and Licensing Fees	
Switchyard	
Political Concessions & Area Development Fees	
Startup/Testing (Fuel & Consumables)	
Initial Fuel Inventory	
Site Security	
Operating Spare Parts	
Permanent Plant Equipment and Furnishings	
Builders Risk Insurance (0.45% of Construction Costs)	
Owner's Contingency (5% for Screening Purposes)	
Total Project Costs, 2022 MM$	
Total Project Costs, 2022 MM$ W AFUDC	
EPC Cost Per TOTAL kW, 2022 $/kW	
Total Cost Per TOTAL kW, 2022 $/kW	
EPC Cost Per INCREMENTAL kW, 2022 $/kW	
Total Cost Per INCREMENTAL kW, 2022 $/kW	
FIXED O&M COSTS (Note 8)	
Fixed O&M Cost - LABOR, 2022 $MM/Yr	
Fixed O&M Cost - OTHER, 2022 $MM/Yr	
LEVELIZED CAPITAL MAINTENANCE COSTS (Note 9)	
Major Maintenance Cost, 2022 $/GT-hr	
Major Maintenance Cost, 2022 $/MWh	
Catalyst Replacement Cost, 2022 $/MWh	
NON-FUEL VARIABLE O&M COSTS (EXCLUDES LEVELIZED CAP. MAINT. COST) (Note 10)	
Total Variable O&M Cost, 2022 $/MWh	
Water Related O&M ($/MWh)	
SCR Reagent, $/MWh	
Other Consumables and Variable O&M ($/MWh)	
ESTIMATED BASE LOAD EMISSIONS, ppm @15% O2 (Note 12)	
NO_X (without SCR/CO Catalyst)	25
CO (without SCR/CO Catalyst)	9
NO_X (with SCR/CO Catalyst)	2
CO (with SCR/CO Catalyst)	2
ESTIMATED BASE LOAD OPERATING EMISSIONS: NATURAL GAS, lb/MMBtu (HHV) (Note 12)	
NO_X	0.007
SO_2	< 0.002
CO	0.004
CO_2	120

Notes
Note 1: Startup times reflect unrestricted, conventional starts for all gas turbines. These start times assume the inclusion of t
Note 2: Startup time to stack emissions compliance is not the same as the start time for gas turbine to MECL. Stack emissio
Note 3: Outage and availability statistics are collected using the NERC Generating Availability Data System. Combined cycle
Note 4: New and clean performance assumed. All performance ratings are based on NATURAL GAS operation. Min load ra
Note 5: Not Used.
Note 6: Water and ammonia consumption are based on performance at annual average conditions and the capacity factors s
Note 7: Capital and fixed O&M costs are presented in 2022 USD $MM.
Note 8: Base O&M costs are based on performance at annual average conditions. Fixed O&M labor assumes 17 additional F
Note 9: Major maintenance costs for frame gas turbines are hours based ($/GT-hr) when average hours per start is >27. Wh
Note 10: Variable O&M costs assume onsite demin treatment system.
Note 11: Not used.
Note 12: Emissions estimates are shown for steady state operation at ISO conditions. Estimates account for the impacts of S

Attachment 3.1 Stakeholder Materials

IRP Public Stakeholder Meeting

August 18, 2022

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

Safety share

CenterPoint Energy

Know your exits

- Whenever you are entering a public area or a guest in a facility such as this, always know your exits. Take note of the signs
- There are two emergency exits, immediately behind me, Additionally, there are exit doors directly behind you – once through the door, to the left is the main entrance into the building. Should the main entrance be blocked there is an exit to the right of this room through a set of doors leading to the loading dock area

Visualize for safety

- When you enter a new space, visualize that an emergency – like a fire, bad weather, or an earthquake – could happen there and consider how you can respond
- The best way is to prepare to respond to an emergency before it happens. Few people can think clearly and logically in a crisis, so it is important to do so in advance, when you have time to be thorough

Fire

- Evacuate the building and move to the back of the CNP Plaza parking lot, near the YWCA

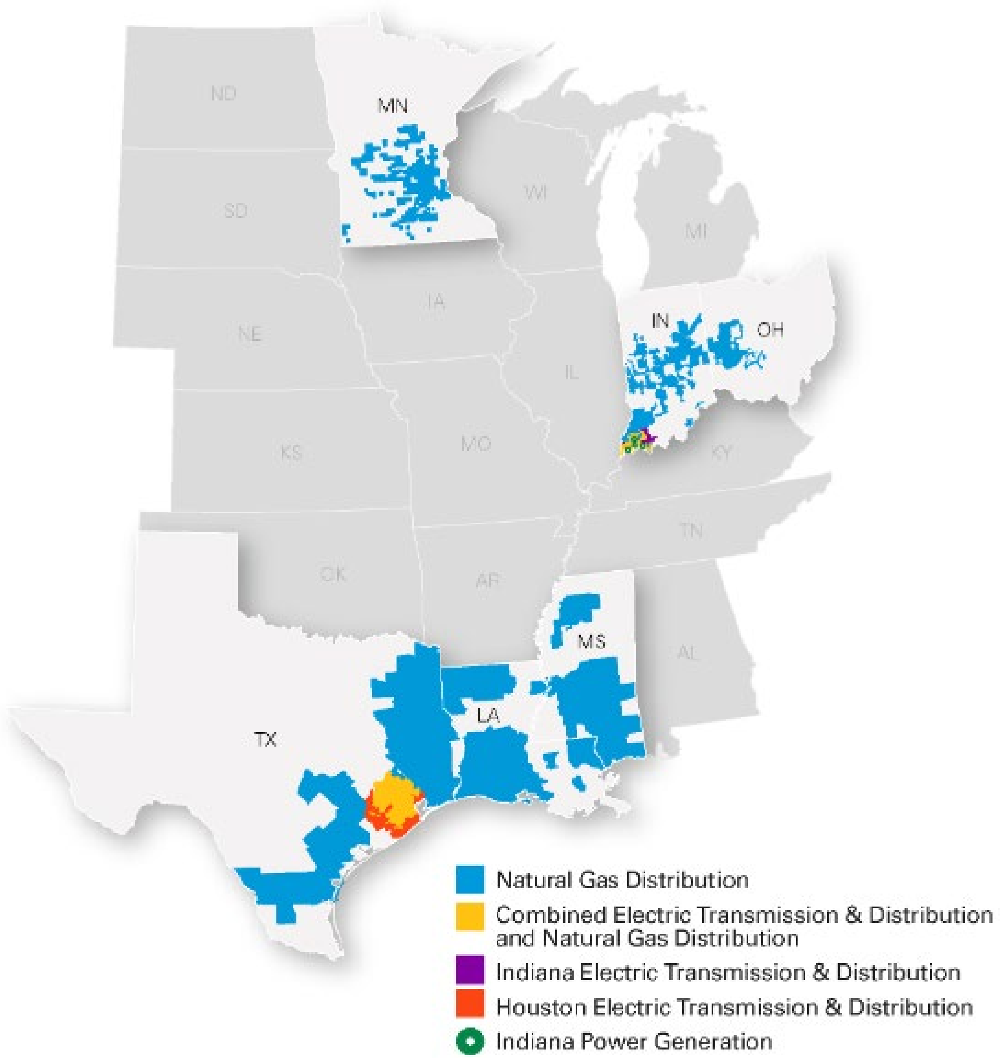
Bad Weather

- During a tornado warning, stay away from windows, glass doors, and outside walls
- Move in an orderly fashion to the stairwell, just outside of the lobby in the main entrance way

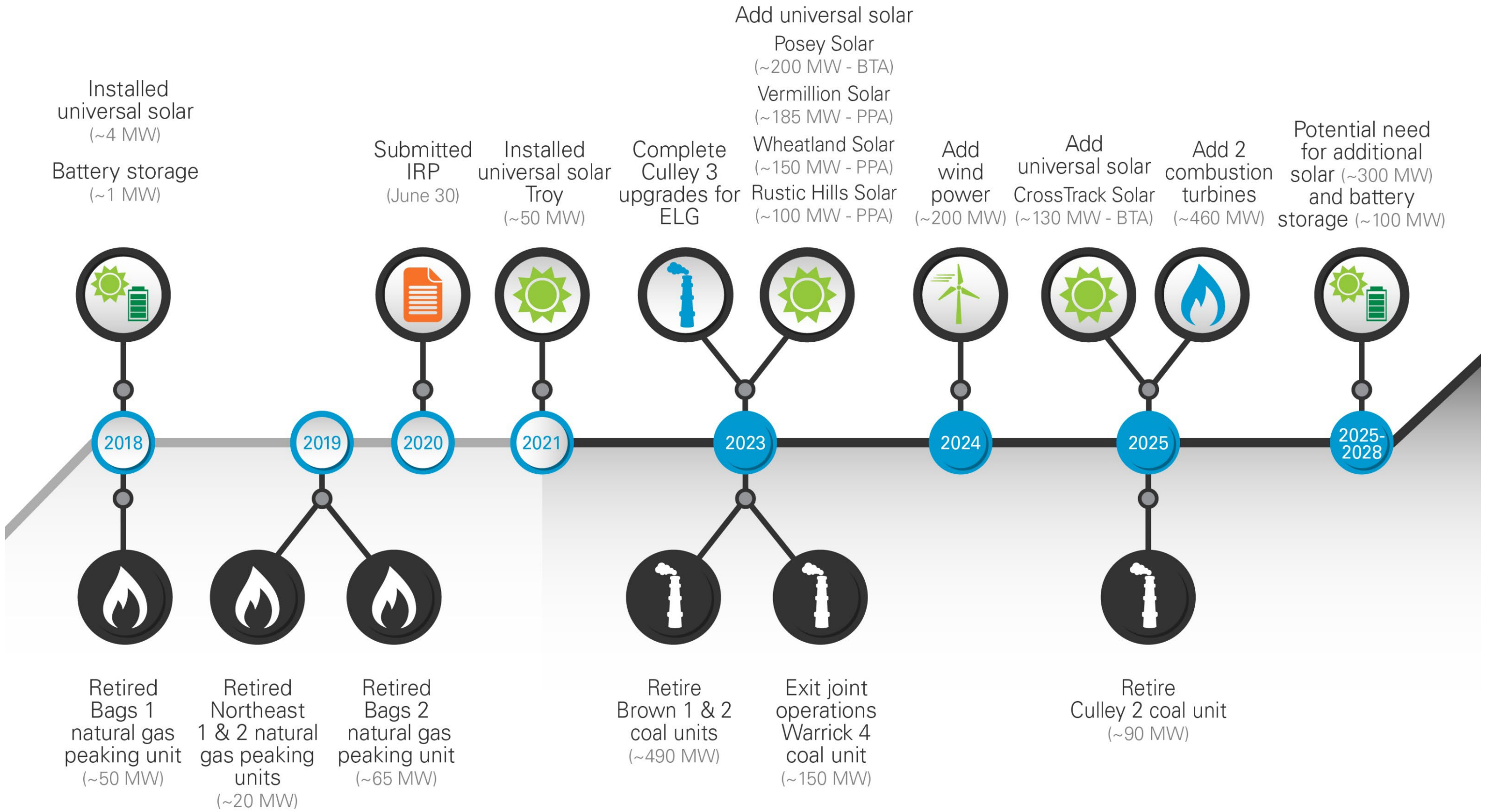
Earthquake

- Move under the desk where you are sitting, facing away from glass, and cover your head and face
- Once shaking has subsided, move in an orderly fashion towards the nearest exit and move to the back of the CNP Plaza parking lot, near the YWCA

Our Businesses



Generation Transition Timeline



Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
RFP = Request for Proposal

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2022/2023 IRP Process

Matt Rice
Director, Regulatory and Rates

Agenda

Time		
9:00 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
9:40 a.m.	2022/2023 IRP Process	Matt Rice, CenterPoint Energy Director Regulatory & Rates
9:55 a.m.	Draft Objectives & Measures	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
10:20 a.m.	EnCompass Software	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
10:35 a.m.	Break	
10:45 a.m.	All-Source RFP	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
11:20 a.m.	Lunch	
12:00 p.m.	MISO Update	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
12:35 p.m.	Environmental Compliance Update	Scott Duhon, CenterPoint Energy Director of Environmental Compliance & Policy
1:05 p.m.	DSM Market Potential Study	Jeffrey Huber, Principal, Energy Efficiency, GDS Associates
1:30 p.m.	Break	
1:40 p.m.	Draft Load Forecast Methodology	Michael Russo, Forecast Consultant - Itron
2:00 p.m.	Resource Options	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
2:20 p.m.	Draft Reference Case Market Inputs and Scenarios	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:00 p.m.	Stakeholder Questions and Feedback	Moderated by Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:30 p.m.	Adjourn	

Meeting Guidelines

CenterPoint Energy

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the “React” feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open up the floor for “clarifying questions,” thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address.
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.

Directors Report Feedback

- CEI South always utilizes feedback from the Director's report for continuous improvement opportunities

Improvement Opportunities	Positive Comments
One optimization run with a minimum of constraints	Significant improvements in all aspects of the IRP
Break out EE bundles into C&I and residential	Risk and uncertainty analysis and discussion in the IRP are well done
Allow DERs to participate in RFP	Wide range of alternative candidate portfolios
Consider sub-hourly to capture value of ancillary services	

Commitments for 2022/2023 IRP

- Will strive to make every encounter meaningful for stakeholders and for us
- The IRP process informs the selection of the preferred portfolio
- Utilize an All-Source RFP to gather market pricing & availability data
- Utilize EnCompass software to improve visibility of model inputs and outputs
- Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- Will conduct technical meetings with interested stakeholders who sign an NDA
- Evaluate options for existing resources
- The IRP will include information presented for multiple audiences (technical and non-technical)
- Will provide modeling data to stakeholders as soon as possible
  - Draft Reference Case results – October 4th to October 31st
  - Draft Scenario results – December 6th to December 20th
  - Full set of final modeling results - March 7th to March 31st

Proposed 2022/2023 IRP Process

CenterPoint Energy

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Reference Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling
7. Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

2022/2023 Stakeholder Process

August 18, 2022	October 11, 2022	December 13, 2022	March 14, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Draft Reference Case Modeling Results • Probabilistic Modeling Approach and Assumptions	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs	• Final Reference Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

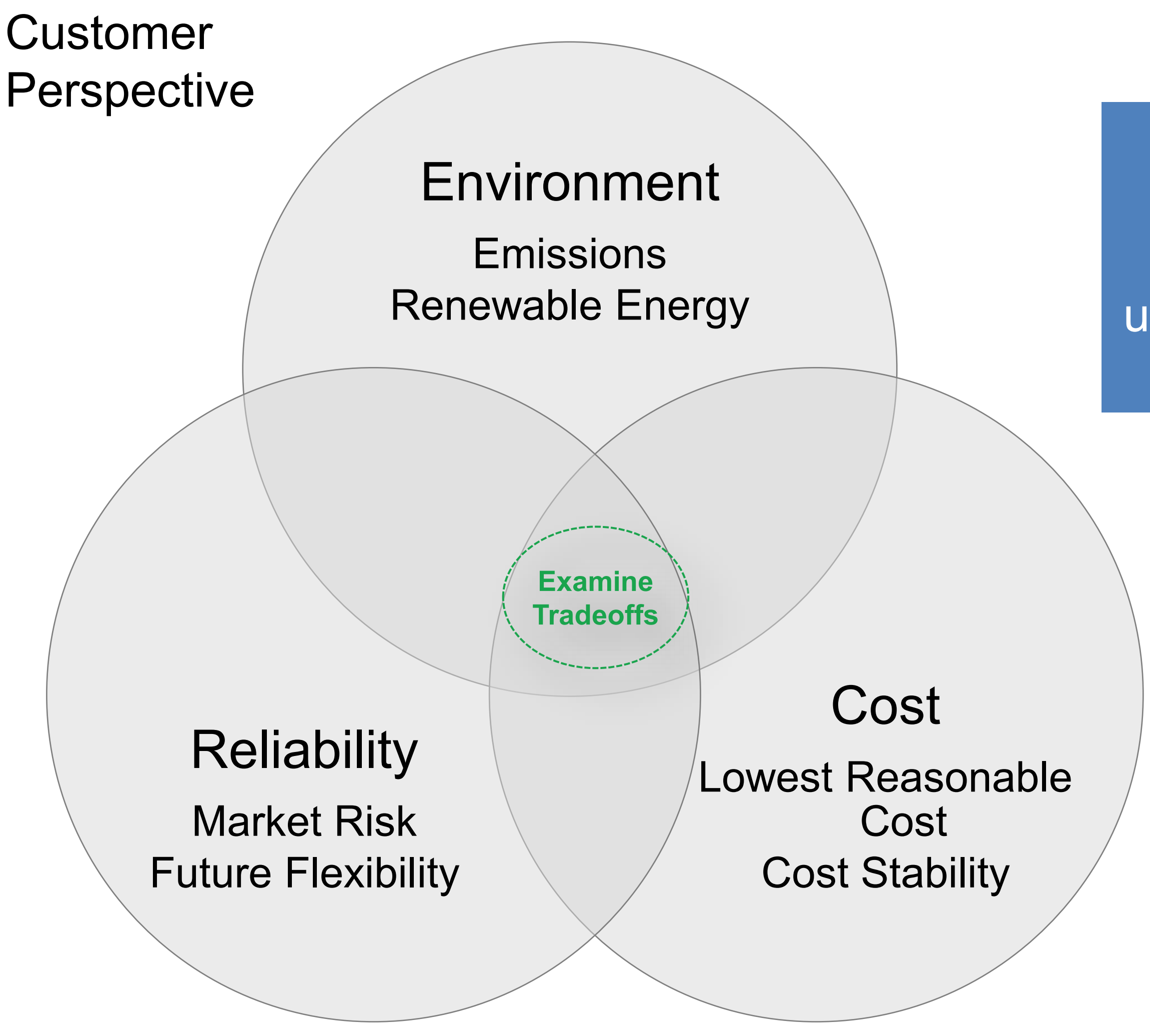
Draft Objectives and Measures

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

IRP Overview

- **Purpose:** Evaluate CenterPoint Energy's current energy resource portfolio and a range of alternative future portfolios to meet customers' electrical energy needs in an affordable, system-wide manner
- **Process:** Evaluate portfolios across many objectives
  - Environmental stewardship
  - Market and price risk, and future flexibility
  - System flexibility to provide backup resources
  - Reliability
  - Resource diversity
- Each objective is important and worthy of balanced consideration in the IRP process, taking into account uncertainty; Some objectives are better captured in portfolio construction than as a portfolio measure
- The measures allow the analysis to compare portfolio performance and potential risk on an equal basis

EACH portfolio will have tradeoffs



Each portfolio will be tested against all objectives and metrics. This evaluation will ultimately result in the selection of the preferred portfolio.

IRP Draft Objectives & Measures

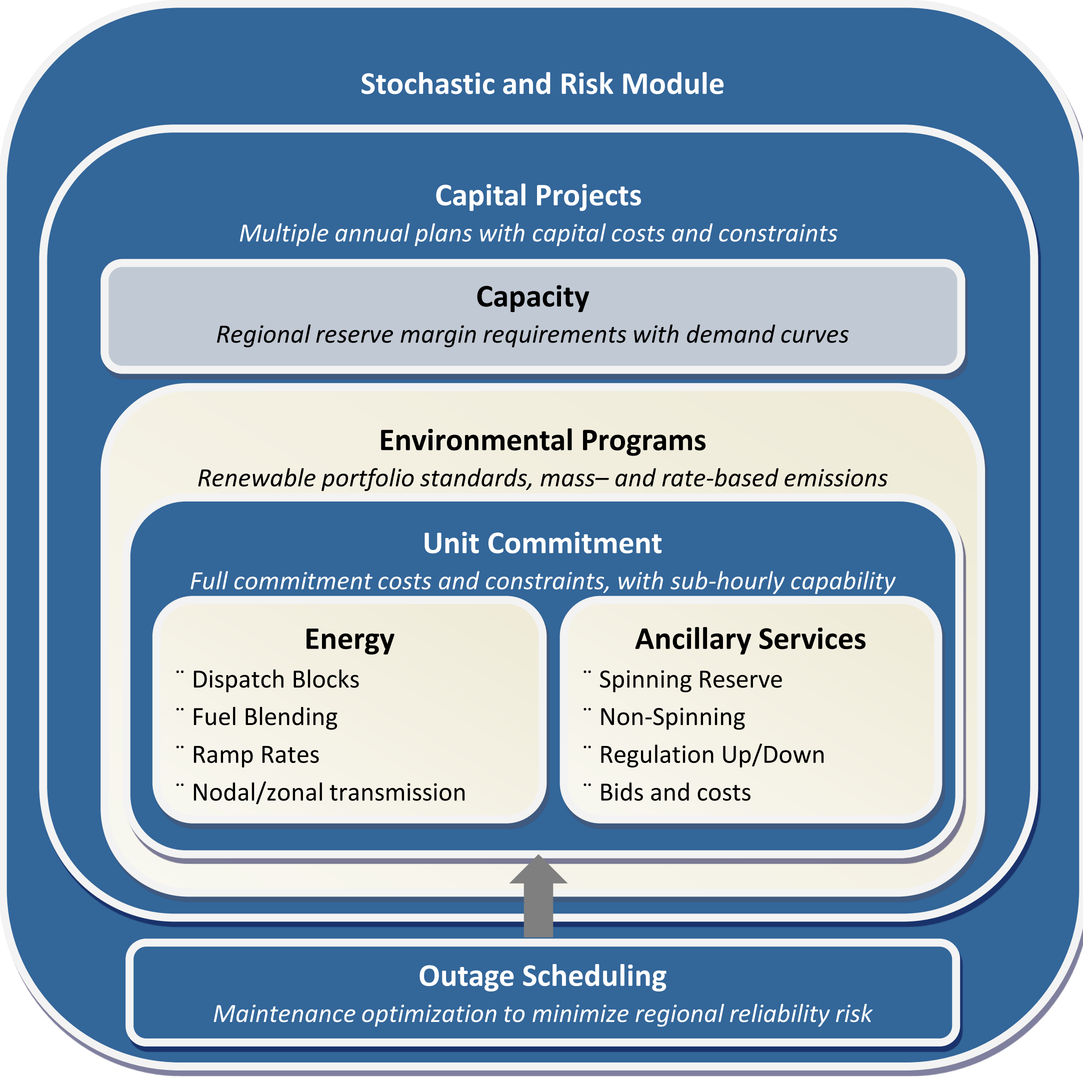
Objective	Potential Measures	Unit
Affordability	20 year NPVRR	$
Environmental Sustainability	CO_2 Intensity	Tons CO_2/kwh
Reliability	Must Meet MISO Planning Reserve Margin Requirement in All Seasons	UCAP MWs
	Spinning Reserve\Fast Start Capability	% of Portfolio MW's That Offer Spinning Reserve\Fast Start
Market Risk Minimization	Energy Market Purchases or Sales	%
	Capacity Market Purchases or Sales	%
Execution	Assess Challenges of Implementing Each Portfolio	Qualitative

EnCompass

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

What is EnCompass?

- Robust production cost and capacity expansion software developed by Anchor Power Solutions
- Currently serves as the basis for regulatory filings in 17 states
- Combines a time series data model with performance options for managing runtime and complexity, while always maintaining chronological constraints



What are EnCompass' Capabilities?

CenterPoint Energy

- Can import and export data into non-proprietary, easy to read spreadsheets
- Has built-in high-level summaries and detailed dispatch reports that support transparency
- Can solve for seasonal capacity obligations, like those currently proposed by MISO
- Can co-optimize dispatch of storage along with other traditional resource types
- Can perform sophisticated stochastic modeling of variables to assist in evaluating risk
- Can incorporate ramp rates, startup times, and startup costs; data items that most traditional long-term models ignore

ANCHOR POWER SOLUTIONS

ENCOMPASS POWER PLANNING SOFTWARE

Who uses EnCompass?

CenterPoint Energy

- EnCompass is licensed by utilities, consultants, and stakeholders as a powerful and accurate tool

AES Indiana

Dairyland Power Cooperative

DTE Energy

Duke Energy

Great River Energy

IMPA Indiana Municipal Power Agency

minnesota power

Otter Tail Power Company

PNM Resources

TVA

Xcel Energy

1898 & Co — Part of Burns & McDonnell

...and many more!

All-Source RFP

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

All-Source RFP Overview

- CenterPoint's 2022 All-Source RFP follows a very similar process as the 2019 All-Source RFP
- Sought feedback and incorporated input from stakeholder groups prior to issuing the RFP
- The guiding principles of the RFP are to conduct a process that is:
  - Objective
  - Fair
  - Open
- Issued advanced notice of RFP
- Open to continued feedback for future RFPs

All-Source RFP Purpose

- The All-Source RFP will help inform CenterPoint Energy's 2022/2023 Integrated Resource Plan modeling
- From the proposals received, CenterPoint Energy can better understand and access current market data

All-Source RFP Overview

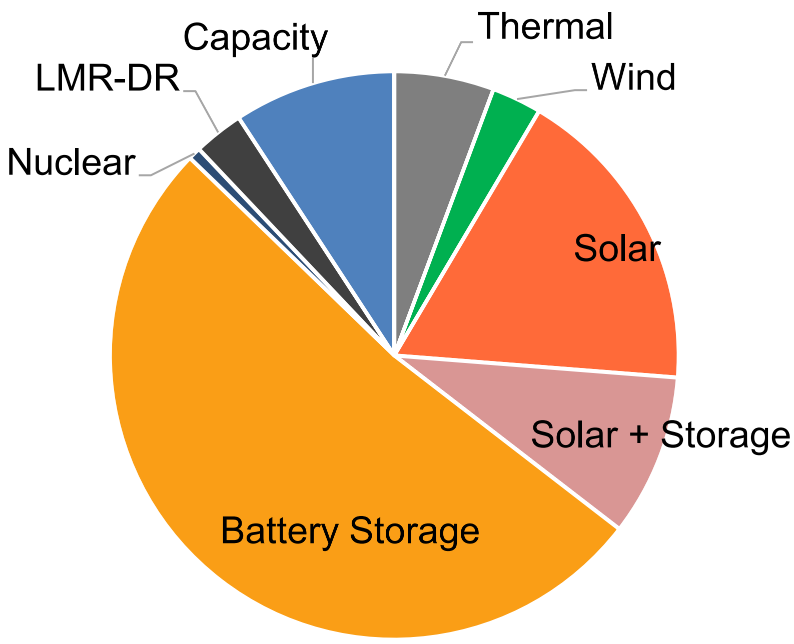
- Open and non-limiting
- Technologies
  - Renewables and storage
  - Thermal
  - Load modifying resources and demand resources
  - Capacity only
- Eligible transaction structures
  - PPA
  - Asset purchase
  - Renewable project in development
  - Demand-side contracts
  - Capacity only contracts
- Resources to be accredited prior to March 1st, 2027

RFP Key Dates

RFP Issued	Wednesday, May 11, 2022
Notice of Intent, NDA, and Respondent Application Due	Friday, May 27, 2022
Pre-Bid Meeting	Wednesday, June 1, 2022
Proposal Submittal Due Date	Tuesday, July 5, 2022
Initial Proposal Review and Evaluation Period	Wednesday, July 6, 2022 – Wednesday August 11, 2022
Proposal Evaluation Completion Target and Short List to CenterPoint For Further Due Diligence	Friday, August 12, 2022

PRELIMINARY RFP STATISTICS

As part of the RFP, we received 129 proposals from 27 different respondents.



Proposal Breakdown

2022 RFP Responses	Proposal Installed Capacity (MW)	Project Installed Capacity (MW)
Thermal	3,087	1,909
Battery Storage	10,149	1,651
Solar + Storage	2,700	1,400
Capacity	632	557
Solar	2,588	1,529
LMR-DR	64	63
Wind	800	400
Total	20,019	7,508

Summary of RFP Responses

- Received significant number of proposals accounting for a diverse set of generation technologies to help inform IRP modeling
- Consistent with industry trend of higher pricing compared to proposals seen in recent years potentially impacted by:
  - Supply chain and COVID impacts
  - Inflation
  - Solar market uncertainty due to Department of Commerce Anti-Dumping/Countervailing Duties Investigation
  - Uyghur Forced Labor Prevention Act (UFLPA)
  - MISO generator interconnection queue
- IRP scenario modeling to help evaluate portfolio replacement decisions under varying future technology costs

MISO Update

Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

What is MISO?

- **M**idcontinent **I**ndependent **S**ystem **O**perator
- In 2001, MISO was approved as the first Regional Transmission Organization (RTO)
  - MISO has operational authority: the authority to control transmission facilities and coordinate security for its region to ensure reliability
  - MISO is responsible for dispatch of lowest cost generation units: MISO's energy market dispatches the most cost effective generation to meet load needs
- MISO is divided into 10 Local Resources Zones (LRZ), Indiana is part of Zone 6, which includes northwest Kentucky (Big Rivers Electric Cooperative)
- Each LRZ has its own planning requirements in regard to energy and capacity
- Each Zone's ability to rely on neighboring Zones depends largely on transmission infrastructure. Based on MISO's Local Clearing Requirement (LCR), approximately 70% of CenterPoint's generation must be physically located within MISO Zone 6

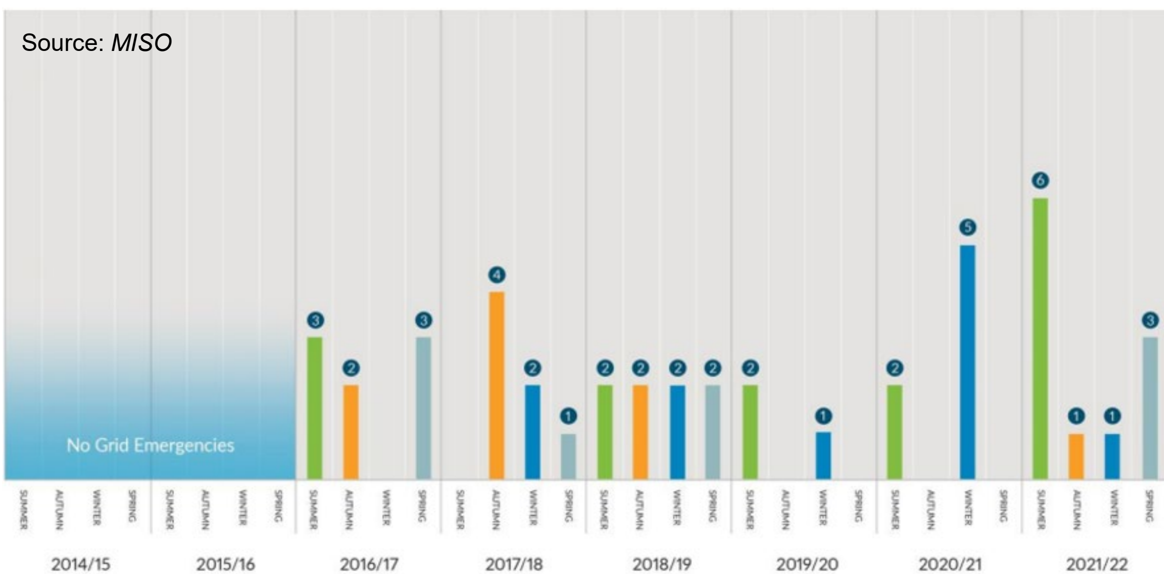
Source: *MISO*

MISO Updates

- New technologies, regulations and policies are changing market dynamics
  - Ongoing power supply fleet transition MISO-wide through resource retirements and increasing intermittent resource additions
  - Corresponding reduction in excess capacity and/or energy during certain periods across MISO is resulting in changes to MISO's Resource Adequacy design
  - In September 2020 FERC issued order 2222, which will allow for distributed energy resources to participate in the market once implemented in MISO

MISO Resource Adequacy

- One of MISO's key functions is to facilitate the availability of adequate and cost-effective resources to reliably meet peak demand in the MISO region
- With MISO's ongoing power supply fleet transition, resource adequacy must evolve to account for new technologies and impacts due to seasonal weather



MISO Resource Adequacy

- MISO's Market Redefinition efforts have led to a proposed[1] seasonal resource adequacy construct with availability-based accreditation
  - Winter - December, January, February
  - Spring - March, April, May
  - Summer - June, July, August
  - Fall - September, October, November

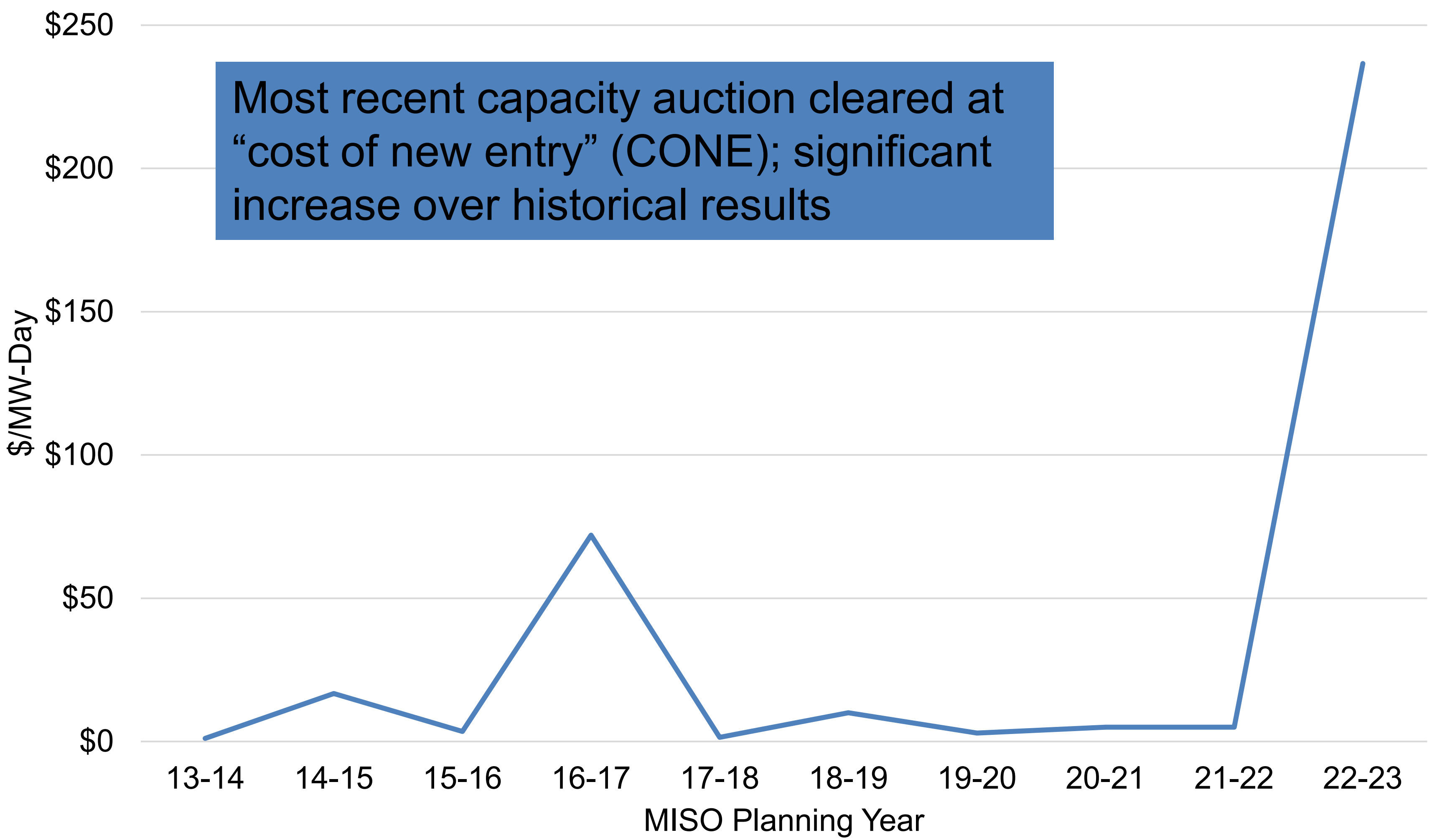
[1]Filed with FERC Nov. 2020 to be effective Sept. 1, 2022 with implementation beginning in PY 2023/24.

Proposed Seasonal Resource Adequacy Construct

MISO's Market Redefinition aims to ensure resources with needed capabilities and attributes will be available in the highest risk periods across the year.

- MISO will calculate sub-annual resource adequacy requirements to align with seasonal needs
  - Loss of load expectation study will calculate the planning reserve margin requirements and local reliability requirements on a seasonal basis
- Accredit resources by season to ensure resources are available when needed, seasonal accredited capacity (SAC)
  - Thermal accreditation will be calculated based on tiered structure within each season, tight hours and non-tight hours
  - Intermittent resource accreditation enhancements are being evaluated; current seasonal accreditation methodology:
    - Wind - Seasonal Effective Load Carrying Capability (ELCC) based on historical performance in 8 peak days per season
    - Non-Wind - based on historical output during hours 15, 16, 17 EST for spring, summer, and fall; Winter accreditation based on hours 8, 9, 19, and 20 EST

MISO Zone 6 Capacity Prices



FERC 2222

- FERC Order No. 2222 removes barriers preventing distributed energy resources (DERs) from participating in organized capacity, energy and ancillary services markets run by regional grid operators such as MISO
- DERs are small-scale power generation or storage resources located on an electric utility's distribution system or behind a customer meter
- Example technologies include solar, storage, demand response, energy efficiency, electric vehicles

FERC 2222

- MISO's proposed approach to 2222 has been submitted for compliance with FERC
  - Proposed implementation date of October 1, 2029
- Planning to incorporate into scenario and/or sensitivity analysis
  - Looking for input and feedback on FERC 2222 in IRP analysis

Environmental Update

Scott Duhon,
Director of Environmental Compliance & Policy

Coal Combustion Residuals Rule

- Final Rule issued April 2015
- Allows continued beneficial reuse of coal combustion residuals
  - Majority of CEI South's fly ash beneficially reused in cement application
  - Scrubber by-product at Culley and Warrick beneficially reused in synthetic gypsum application
- Rule established operating criteria and assessments as well as closure and post-closure care standards
  - Culley West ash pond closure activities were completed in December 2020
  - Culley East ash pond is still operating, with planned closure-by-removal. Closure plan submitted to IDEM in February 2022
  - Brown ash pond is still operating, with planned closure by removal and beneficial reuse. Beneficial reuse activities have commenced
- Part A Rule finalized in August 2020
  - Finalized revised compliance deadline (April 2021) and provided a mechanism to request limited extension for use of ponds. CEI South filed extension requests for A.B. Brown ash pond and F.B. Culley East ash pond in November 2020
    - EPA has not yet issued a decision on either extension request; however, construction of the extension ponds were recently approved by the IURC in Cause No. 45564, and we are proceeding with design and construction per the commitments provided by our submittals to EPA

Effluent Limitation Guidelines

- On September 30, 2015, the EPA finalized its new Effluent Limitation Guidelines (ELGs) for power plant wastewaters, including ash handling and scrubber wastewaters
- The ELGs prohibit discharge of water used to handle fly ash and bottom ash, thereby mandating dry handling of fly ash and bottom ash
- ELG Reconsideration Rule finalized in October 2020 updated the compliance deadline for bottom ash which allows for continued operation of Culley Unit 2 until December 2025, which CNP may do to help support capacity requirements until new combustion turbines and renewables projects are completed; Operation of Culley Unit 2 beyond December 2025 would require completion of a bottom ash handling retrofit
- Culley Unit 3 retrofit of bottom ash to dry handling was completed in 2020; Spray Dryer Evaporator for scrubber wastewater is on schedule for completion in 2023

Clean Water Act 316(b)

- In May 2014 EPA finalized its Clean Water Act 316(b) rule which focuses on impingement and entrainment of aquatic species during water intake
- The final rule did not mandate cooling tower retrofits
- CNP submitted the multi-year entrainment and other required studies for F.B. Culley as required under the rule and proposed modified traveling screens in its NPDES renewal submittal; CEI South is still in discussion with IDEM as to the applicable 316(b) technology
- For purposes of IRP modeling, CEI South is modeling a range of scenarios which would include intake screen modifications and new wedge wire screens for the Culley plant and will assume a 2024 - 2026 deadline for compliance

NOx Ozone Season Allowances

- Revised CSAPR Update Rule finalized in May 2021 significantly reduced amount of ozone season NOx allowances allocated to each state and have significantly increased the cost

Year	Tons Allocated	Tons Purchased	Purchase Cost per Allowance
2018	1,381	350	$200
2019	1,381	1,050	$164
2020	1,379	800	$73
2021*	1,184	600	$2,310
2022**	851	450	$50,000

*2021 – 2022 are Group 3 allowances under the May 2021 rule. 2021 was prorated due to the rule becoming effective after the start of the ozone season, making 2022 the first full season under the Revised CSAPR Update rule.
**2022 purchase quantity is based on generation as of 7/22/2022. Purchase cost is based on market offer price as of 8/4/2022.

Carbon Regulation

- Since 2015 dueling administrations have attempted to finalize carbon regulations under CAA Sect. 111(d)
- The Clean Power Plan (CPP) would have set stringent state emission caps and effectuated a shift in state generation portfolios to significantly increased renewables, which implementation was stayed by the U.S. Supreme Court
- The EPA sought to vacate the CPP and replace it with the Affordable Clean Energy (ACE) rule, which focused on efficiency targets that could be met at an individual unit level
- In June 2022, the U.S. Supreme Court held that the EPA exceeded its authority when it promulgated the CPP's stringent state emission caps that would have required generation shifting within states; While the decision did not go so far as to hold that EPA was explicitly prohibited from promulgating a regulation requiring compliance measures "outside the fence line" for existing units under 111(d), the ACE rule remains the current reference case 111(d) compliance scenario for modeling purposes

Future Regulation - MATS Revisions

CenterPoint Energy

- MATS revision – Mercury & Air Toxics (MATS)
  - In May of 2020, the EPA issued its revised finding that it is not *appropriate and necessary* to regulate coal-fired electric generating units under Section 112 of the CAA; However, EPA did <u>not</u> seek at that time to withdraw the currently applicable MATS standards finalized in 2015
  - In May of 2020 EPA also published its residual risk and technology review of MATS, finding that emissions of hazardous air pollutants (HAPs) have been reduced such that residual risk is at acceptable levels, that there are no developments in 2 HAP emissions controls to achieve further cost-effective reductions beyond the current standards, and no changes to the MATS rule are warranted
  - On January 21, 2022, EPA proposed to revoke its finding that it is not *appropriate and necessary* to regulate coal-fired electric generating units under Section 112 of the CAA, and notified of its intent to review the residual risk and technology review of MATS
  - EPA's actions in January 2022 set the stage for potential updates to the existing MATS limits for mercury and acid gases from coal-fired power plants

Future Regulation – Ozone "Good Neighbor SIP"

CenterPoint Energy

- On April 6, 2022, EPA proposed to further reduce emissions of NOx from coal-fired power plants under Section 126 (or the "Good Neighbor") provision of the CAA, which requires coal-fired power plants in 26 states (including Indiana) to reduce emissions of NOx that EPA has found to contribute to ozone nonattainment in downwind states for the more stringent 2015 Ozone NAAQS
- Beginning in the 2023 ozone season, EPA is proposing to include Indiana coal-fired power plants in a revised and potentially significantly more stringent Cross-State Air Pollution Rule (CSAPR) "NOx Ozone Season Group 3 Trading Program"

Natural Gas

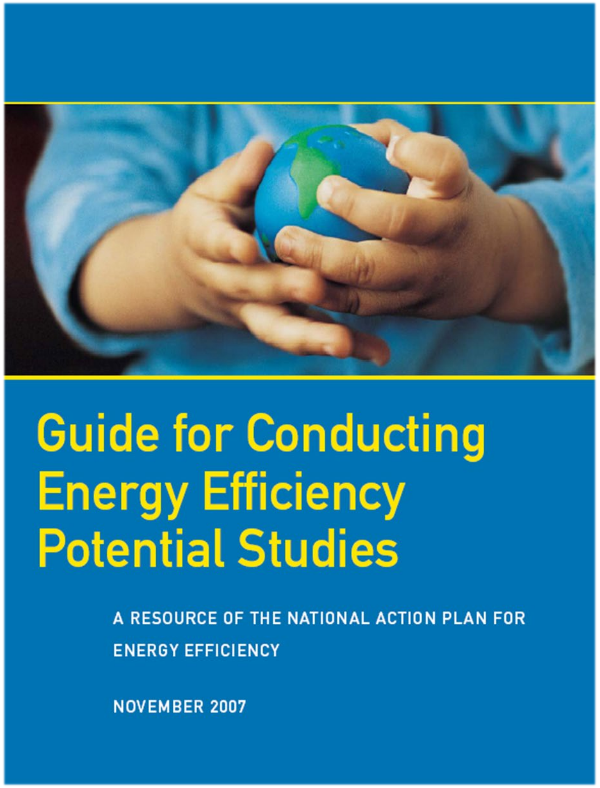
- Clean Water Act Section 401
  - October 2021, the U.S. District Court vacated EPA's 2020 Clean Water Act Section 401 Certification Rule; April 2022, the U.S. Supreme Court stayed the vacatur reinstating the 2020 Rule
- New Source Performance Standards
  - November 2021, the EPA proposed NSPS program rules that would reverse the prior administration's rules and return to the previous methane standards and contain more stringent monitoring requirements and possibly require state specific plans

DSM Market Potential Study

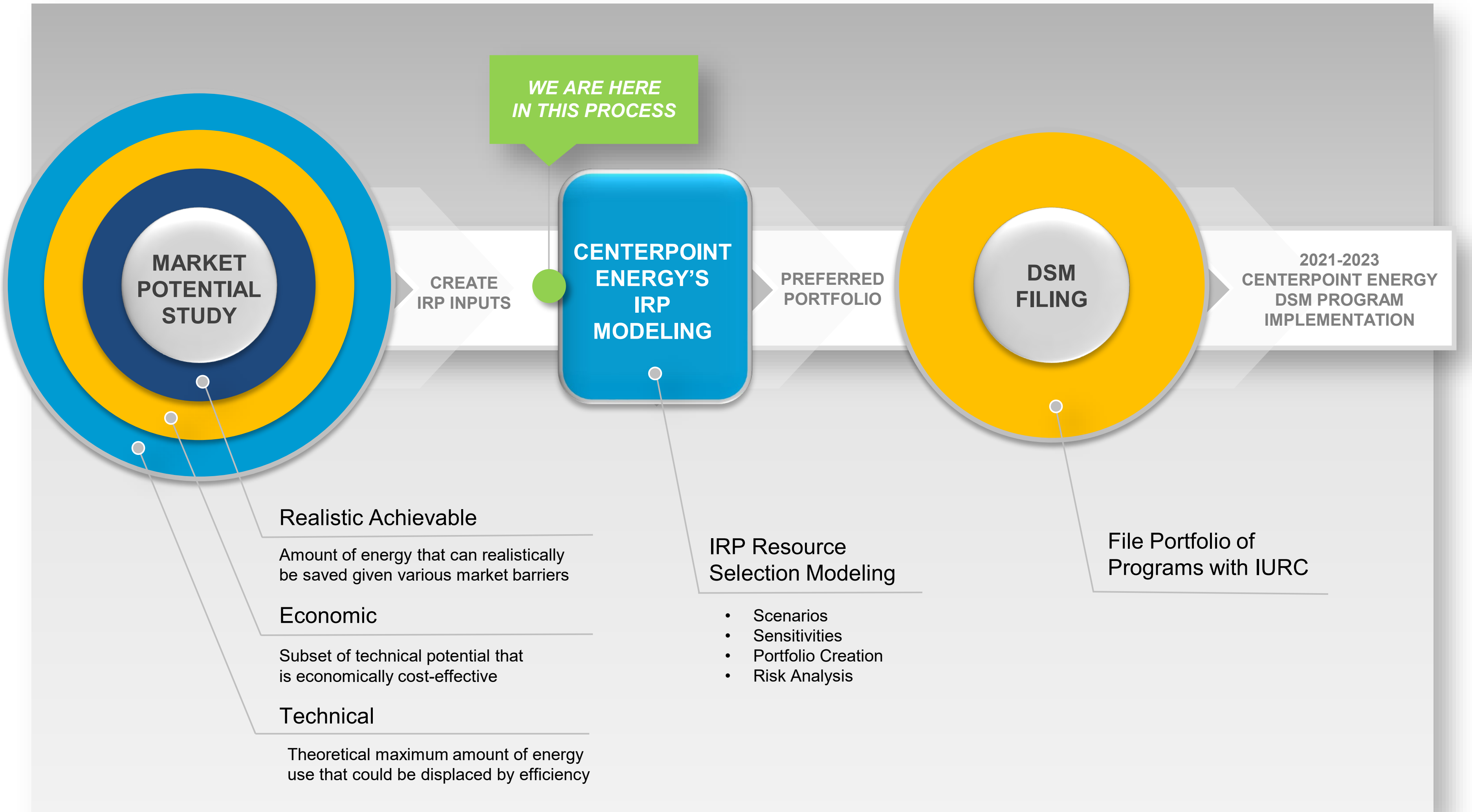
Jeffrey Huber
Principal, Energy Efficiency
GDS Associates, Inc.

Market Potential Studies & IRPs

- What is a Market Potential Study (MPS)?
  - Simply put, a potential study is a quantitative analysis of the amount of energy savings that either exists, is cost-effective, or could be realized through the implementation of energy efficiency programs and policies
- About the CEI South MPS
  - Includes Energy Efficiency (EE) and Demand Response (DR)
  - 2022 MPS is considered a “refresh” and does not include new primary market research
  - MPS analysis covers 2025-2042



Market Potential Studies & IRPs



Types of EE/DR Potential

CenterPoint Energy

TECHNICAL POTENTIAL

All technically feasible measures are incorporated to provide a theoretical maximum potential.

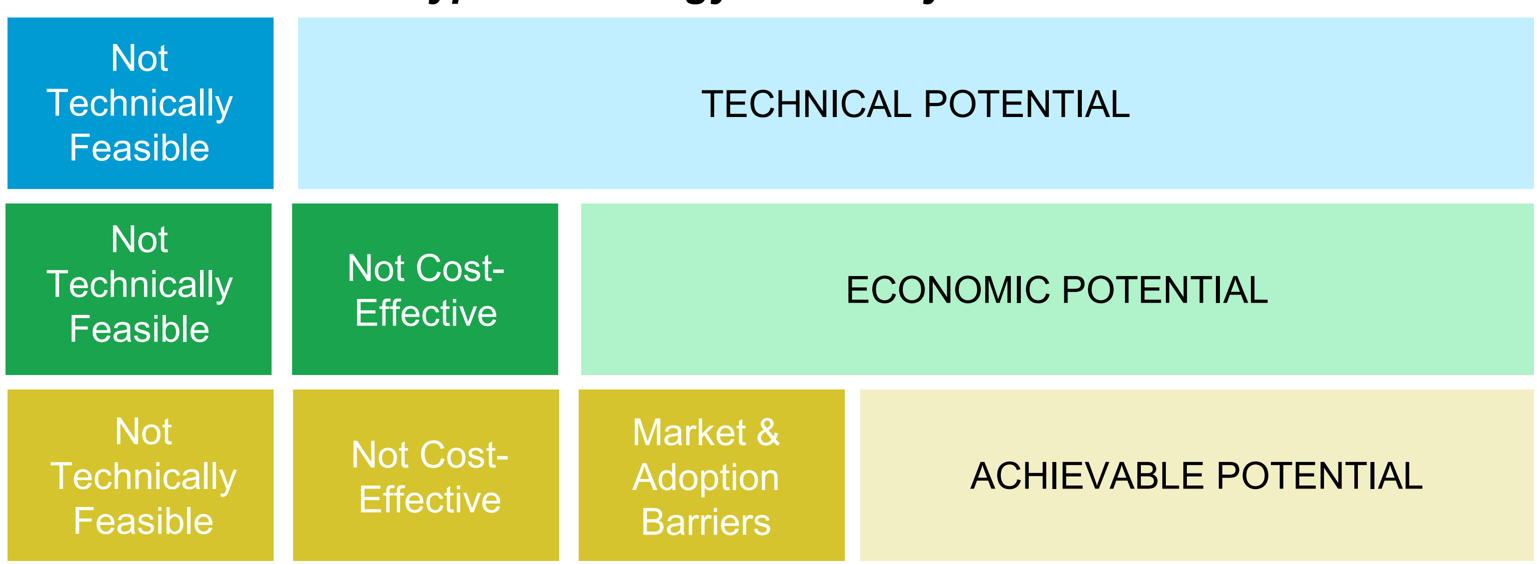
ECONOMIC POTENTIAL

All measures are screened for cost-effectiveness using the UCT Test. Only cost-effective measures are included.

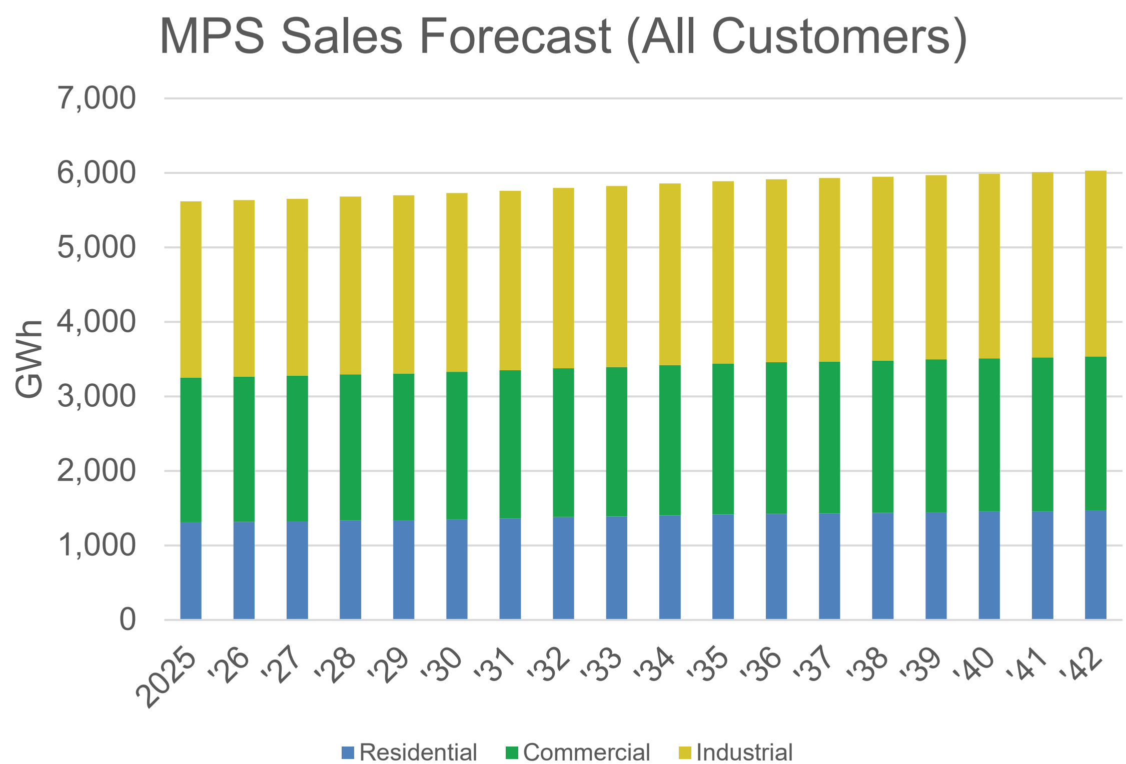
ACHIEVABLE POTENTIAL

Cost-effective energy efficiency potential that can practically be attained in a real-world program delivery case, assuming that a certain level of market penetration can be attained.

Types of Energy Efficiency Potential

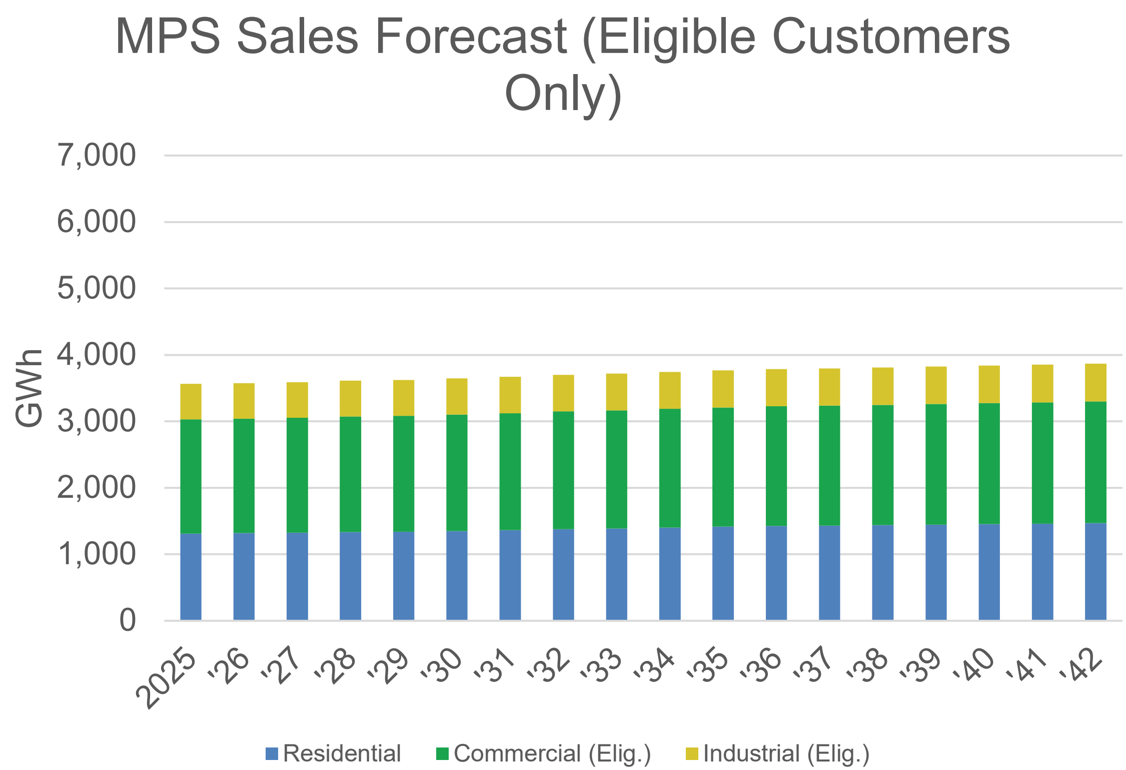


Load Forecast for EE/DR



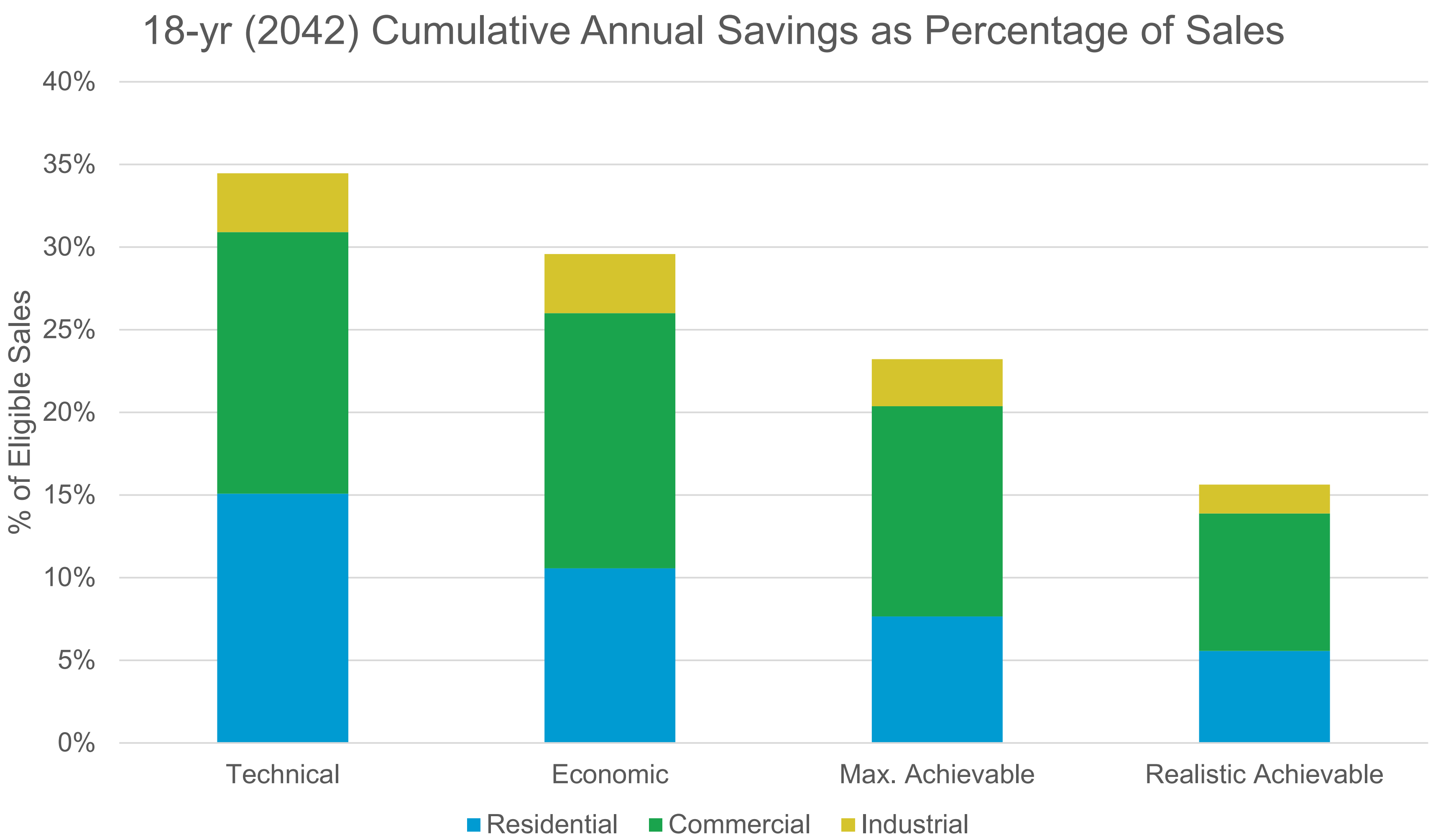
- MPS Sales Forecast reclassifies some load between commercial and industrial to reflect building type vs. rate code
- A substantial portion of the industrial load (and a smaller portion of the commercial load) can opt out of utility DSM programs

Eligible Load for EE/DR

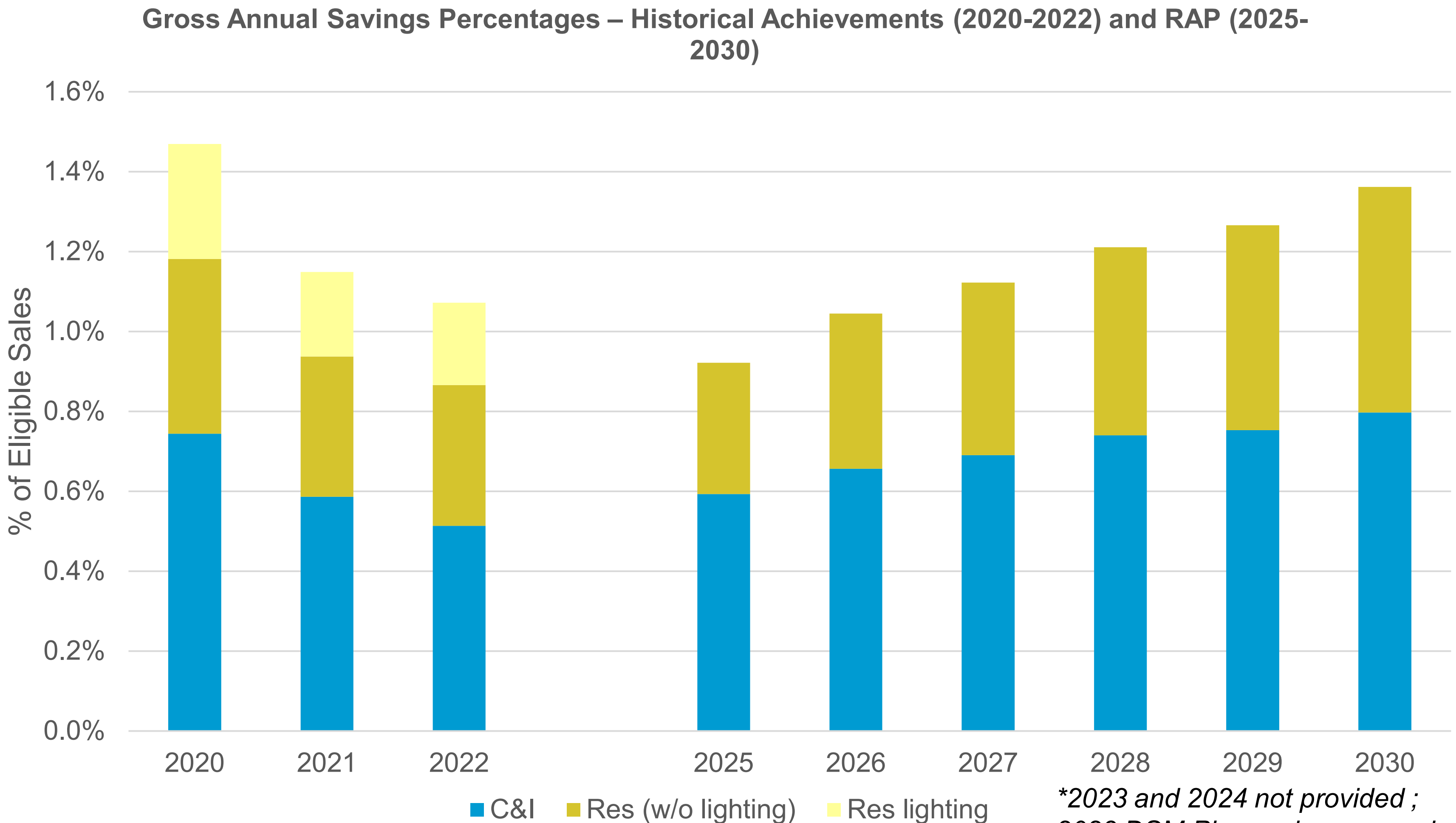


- Opt-out customers are not included in the base case of the MPS

EE Analysis – Summary Results



EE Analysis – Historical Comparison



**2023 and 2024 not provided ;*
2023 DSM Plan under approval
2024 DSM Plan will be extension filing

DR Analysis – Programs Included

- DR programs analyzed include:
  - Direct load control of air conditioning (using thermostats and switches), water heaters, and pool pumps
  - Rate programs include critical peak pricing (with enabling technology and without), peak time rebates, real time pricing, and time of use
- Timing of programs:
  - DLC air conditioning switches expected to fully transition to thermostats by 2029
  - Rate programs starting in 2026 as potential pilots and ramping up starting in 2031

CenterPoint Energy

DR Hierarchy

DR analysis accounts for interactive effects as additional types of demand response programs are added to the mix. The hierarchy places existing DR programs at the top of the list. Rate programs are ordered based on the highest load reduction per customer. The hierarchy for demand response programs is as follows:

1. Direct Load Control
2. Critical Peak Pricing with Enabling Technology (such as a smart thermostat)
3. Critical Peak Pricing without Enabling Technology
4. Real Time Pricing
5. Peak Time Rebate
6. Time of Use

EE/DR Inputs into IRP

- EE Inputs will align with RAP Potential *(but adjusted from gross to net savings)*
- EE Inputs will be provided over three vintages
  - 2025-2027 (3 years)
  - 2028-2030 (3 years)
  - 2031-2042 (12 years)
- For 2025-2027, EE Inputs will be bundled to closely resemble program offerings
  - For remaining vintages, EE inputs will be aggregated at the sector level
- EE Costs will include utility costs (incentives and non-incentive costs)
  - Costs will be adjusted to recognize value of avoided lifetime T&D benefits

EE/DR Inputs into IRP

- Income Qualified Savings will be a going-in resource (i.e. not selectable) as high program costs would likely prohibit selection in the IRP model
  - The cost (and savings) of the income-qualified program will be aligned so that the future income-qualified annual budget maintains the same proportion to the total budget as the current DSM Plan
- Expected Improvements to the DSM Plan
  - Bundles will be sector specific, consistent with request from the prior Director's Report
  - Within a bundle/vintage, the EE Savings are broken out by end-use
  - Cost adjustment to reflect avoided transmission and distribution benefits
  - Consistent with prior IRP DSM Inputs, model will account for full lifetime savings of DSM bundles

EE/DR Inputs into IRP

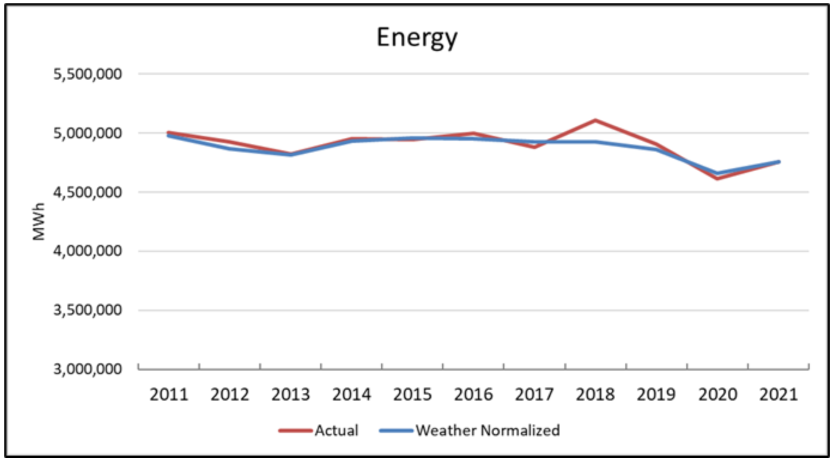
- Bundles for demand response follow the same vintages as Energy Efficiency
- Demand response bundles created for four categories
  - Residential DLC
  - Residential Rates
  - C&I DLC
  - C&I Rates/Interruptible
- DR program provide summer peak savings but expected to provide minimal winter peak and energy value to the portfolio
- Phase out of existing DLC legacy air conditioning switches will be a going-in resource; remaining DR will be modeled as a selectable resource

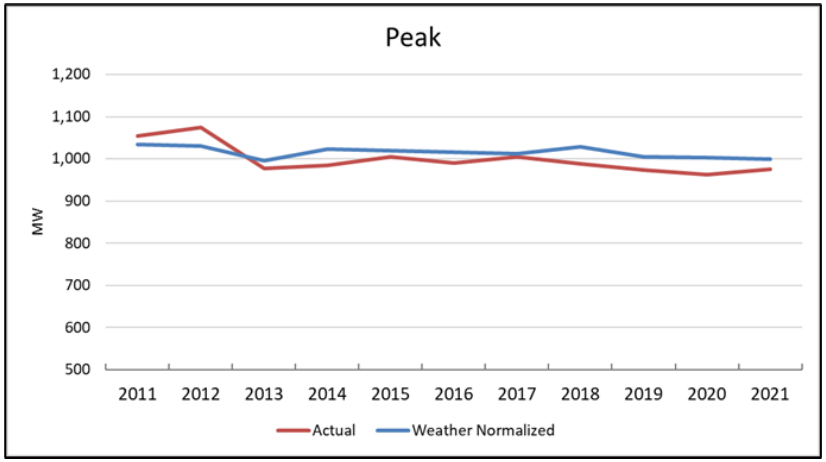
Draft Load Forecast Methodology

Michael Russo
Senior Forecast Consultant - Itron

Historical Energy and Peaks Trends

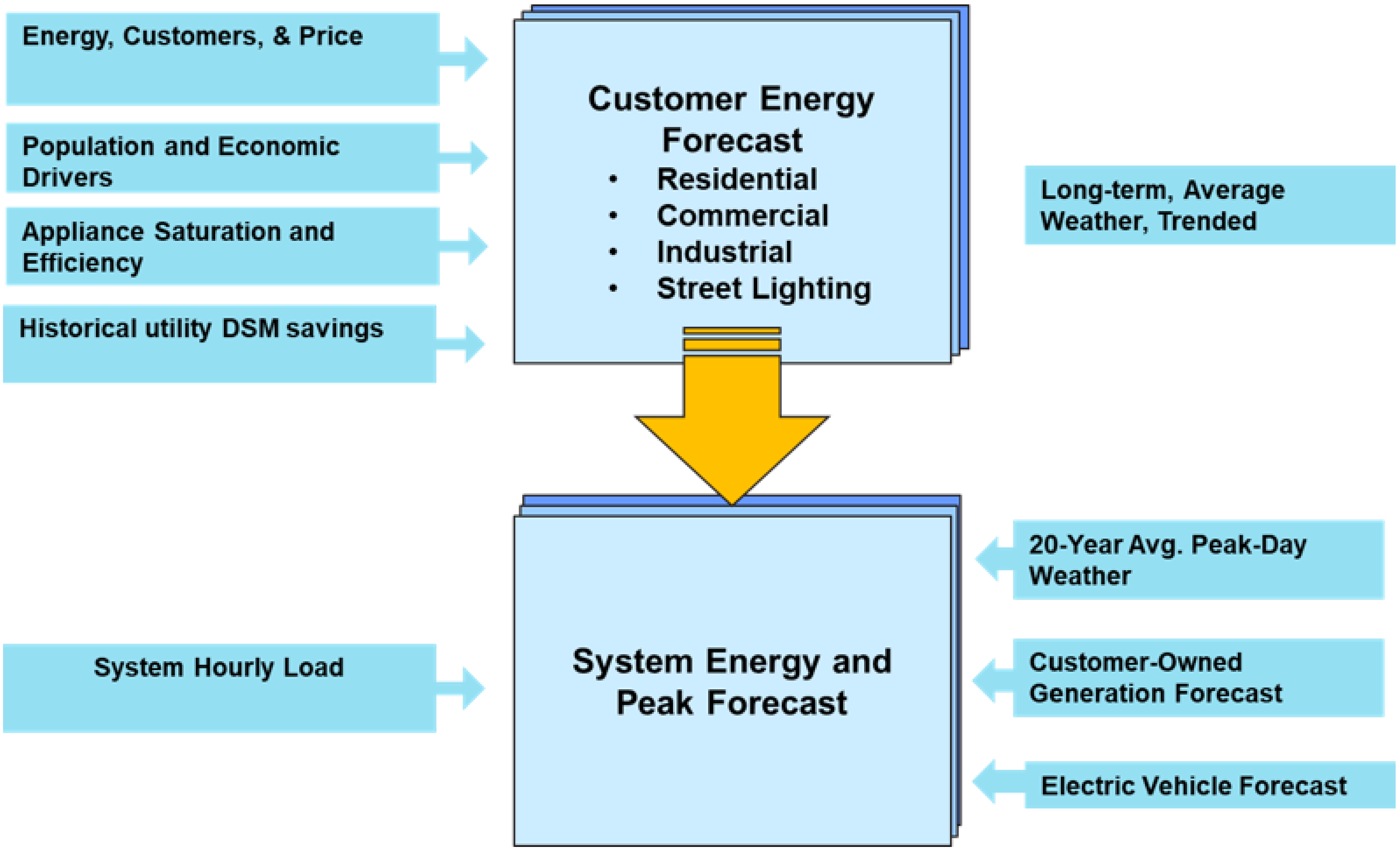
- Historical decline in energy and peaks despite moderate economic and customer growth
  - Strong efficiency gains reflecting new and existing Federal codes and standards as well as utility sponsored energy efficiency program savings
  - 0.4% average annual decline in energy and peaks; 2011-2021, weather normalized





*Excludes the loss of load in 2017 from large customer's cogeneration

Bottom-Up Forecast Approach



Economic Drivers

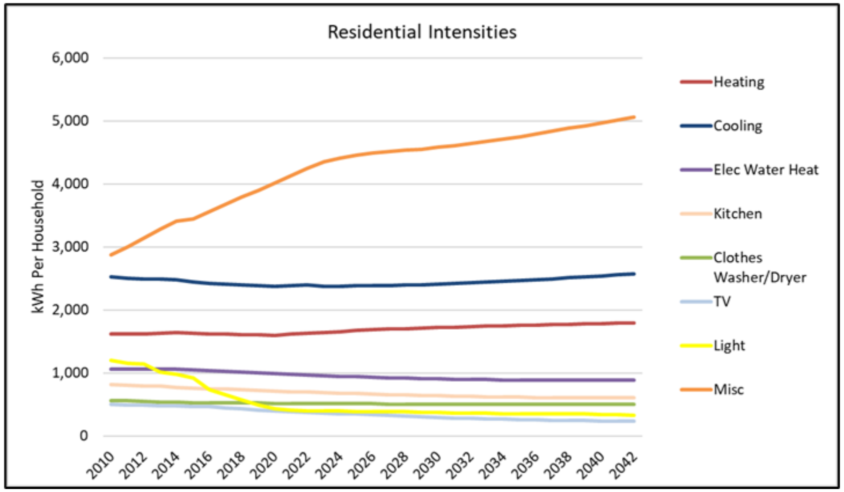
IHS Markit forecast for the Evansville MSA and Indiana

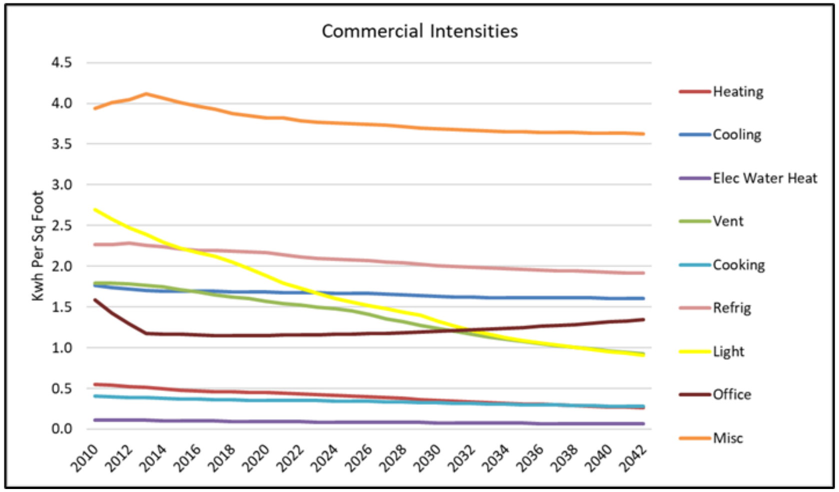
- Residential Sector
  - Households: 0.4% CAGR
  - Real Household Income: 1.6% CAGR
  - Household Size: -0.3% CAGR
- Commercial Sector
  - Non-Manufacturing Output: 1.5% CAGR
  - Non-Manufacturing Employment : 0.3% CAGR
  - Population: 0.4% CAGR
- Industrial Sector
  - Manufacturing Output: 2.2% CAGR
  - Manufacturing Employment: -0.6% CAGR

*CAGR= Compound average growth rate from 2022-2042

End-use intensity Trends

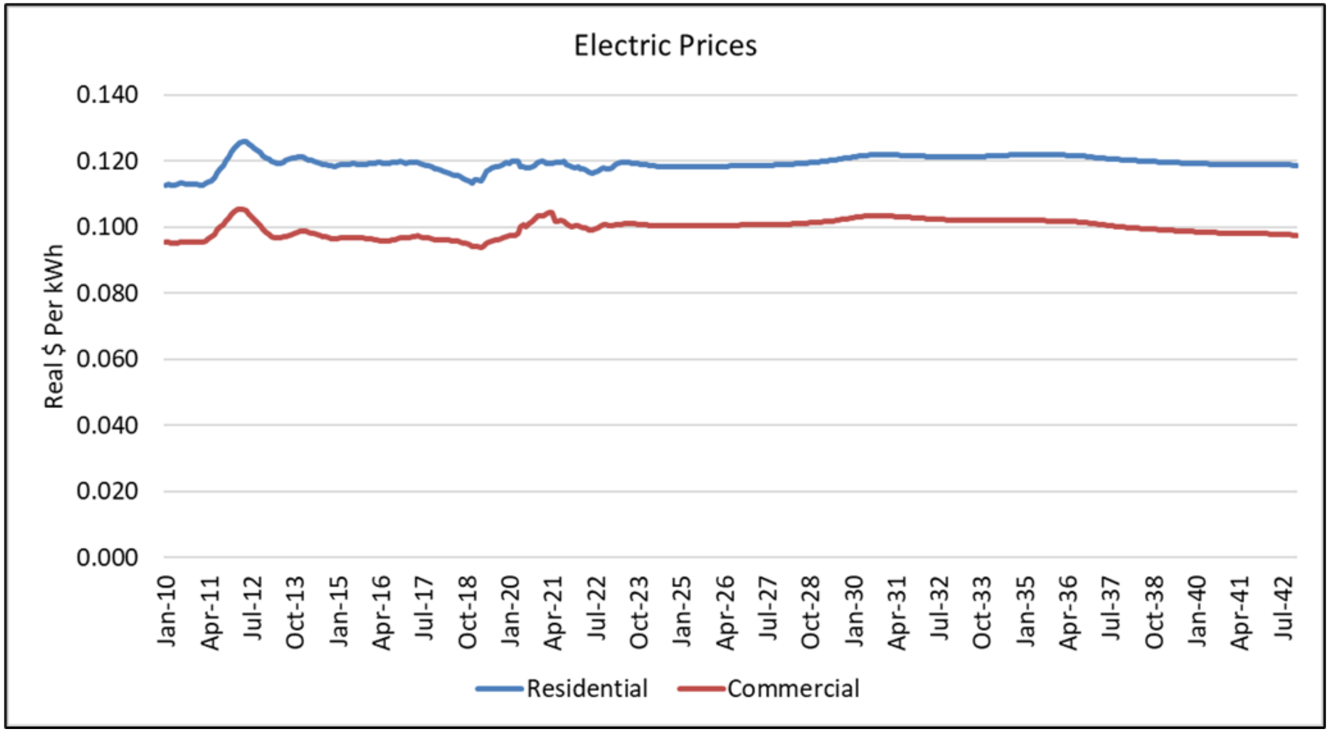
- Residential and Commercial Buildings
  - Reflects change in end-use ownership and efficiency trends
  - Based on the most recent Energy Information Administration's Annual Energy Outlook
    - Calibrated to the Indiana electric service territory
    - Total residential intensity increases at 0.2% CAGR (2022-2042)
    - Total commercial intensity decreases at 0.8% CAGR (2022-2042)





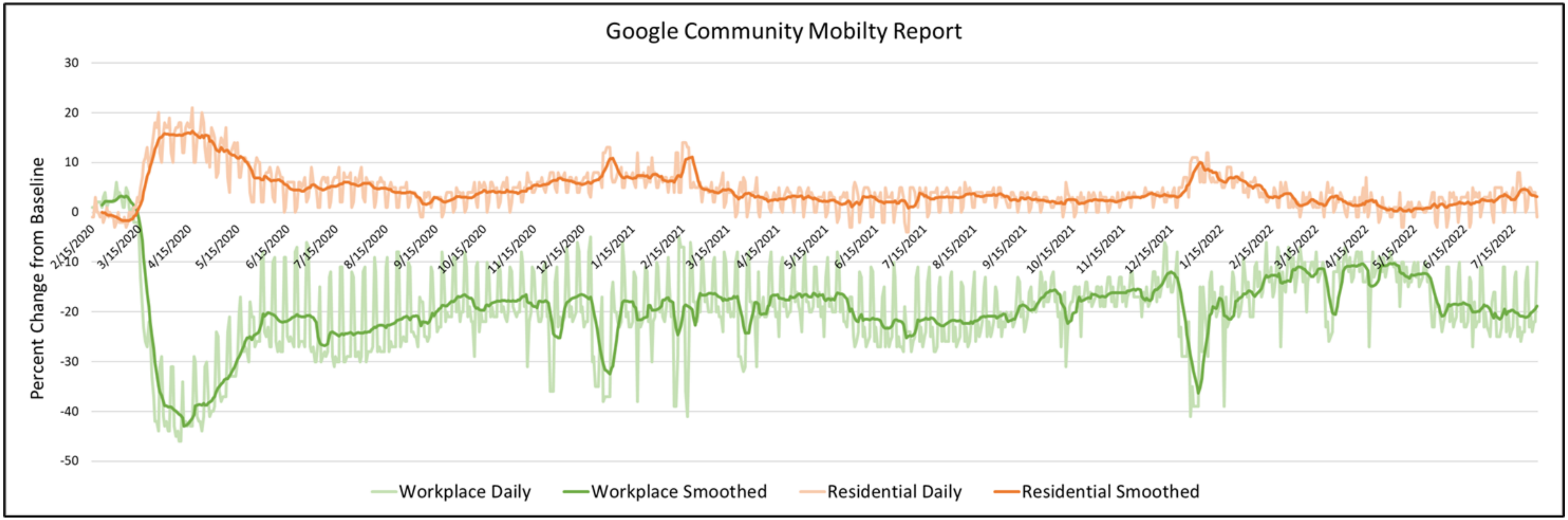
Electricity Prices

- Historical prices based on 12 month rolling average rate (total revenue $/total kWh), converted from nominal to real dollars
- Forecasted price increase/decrease based on Energy Information Administration's regional forecast

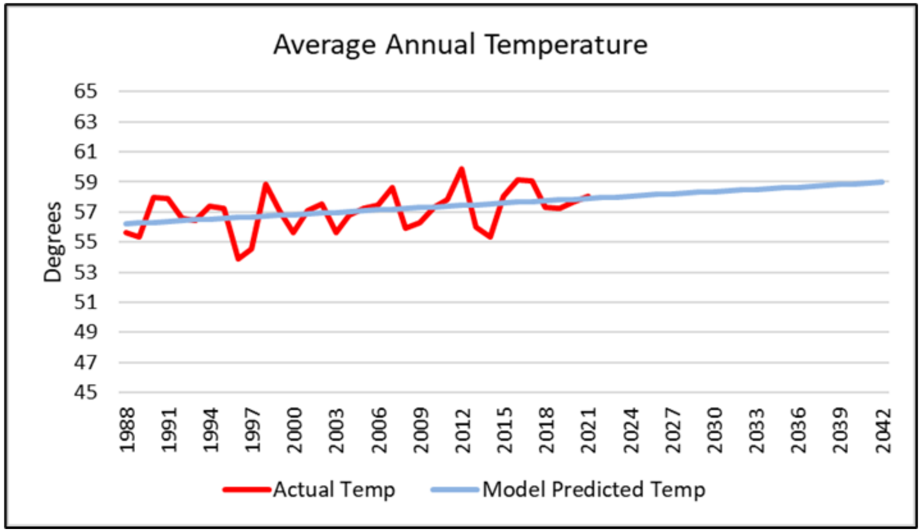


COVID Impact on Electricity Usage

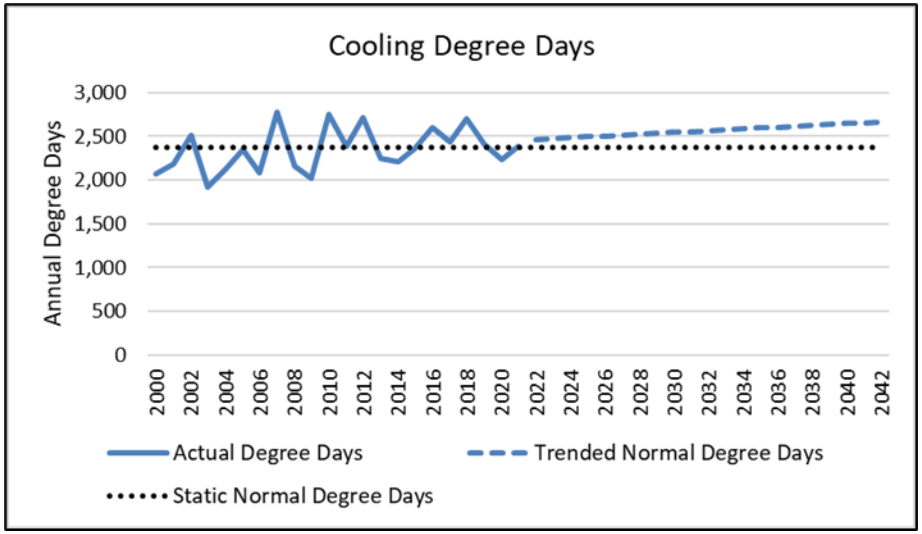
- Increase in residential sales, decrease in commercial sales
- Google Community Mobility Reports data used to explain historical deviations from normal usage
  - Vanderburgh County data
  - Residential and Workplace categories used

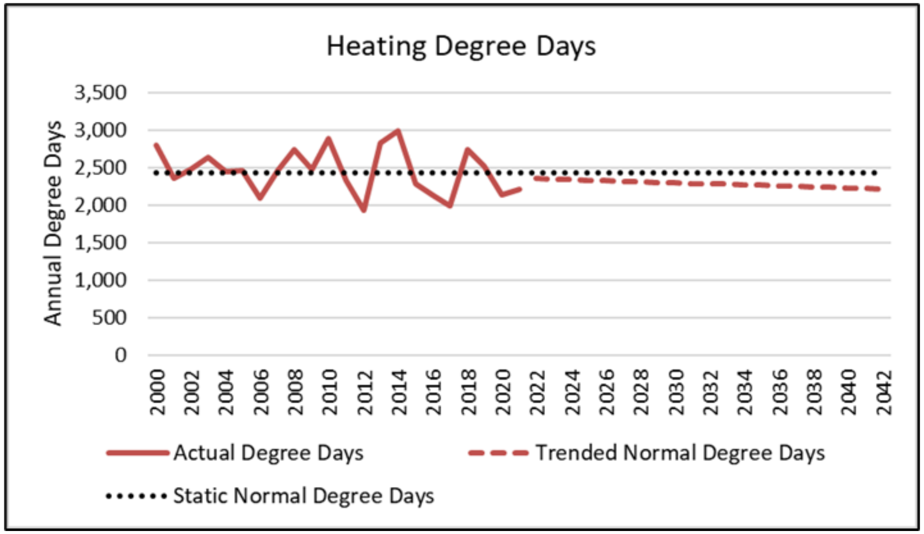


Trended Normal Weather

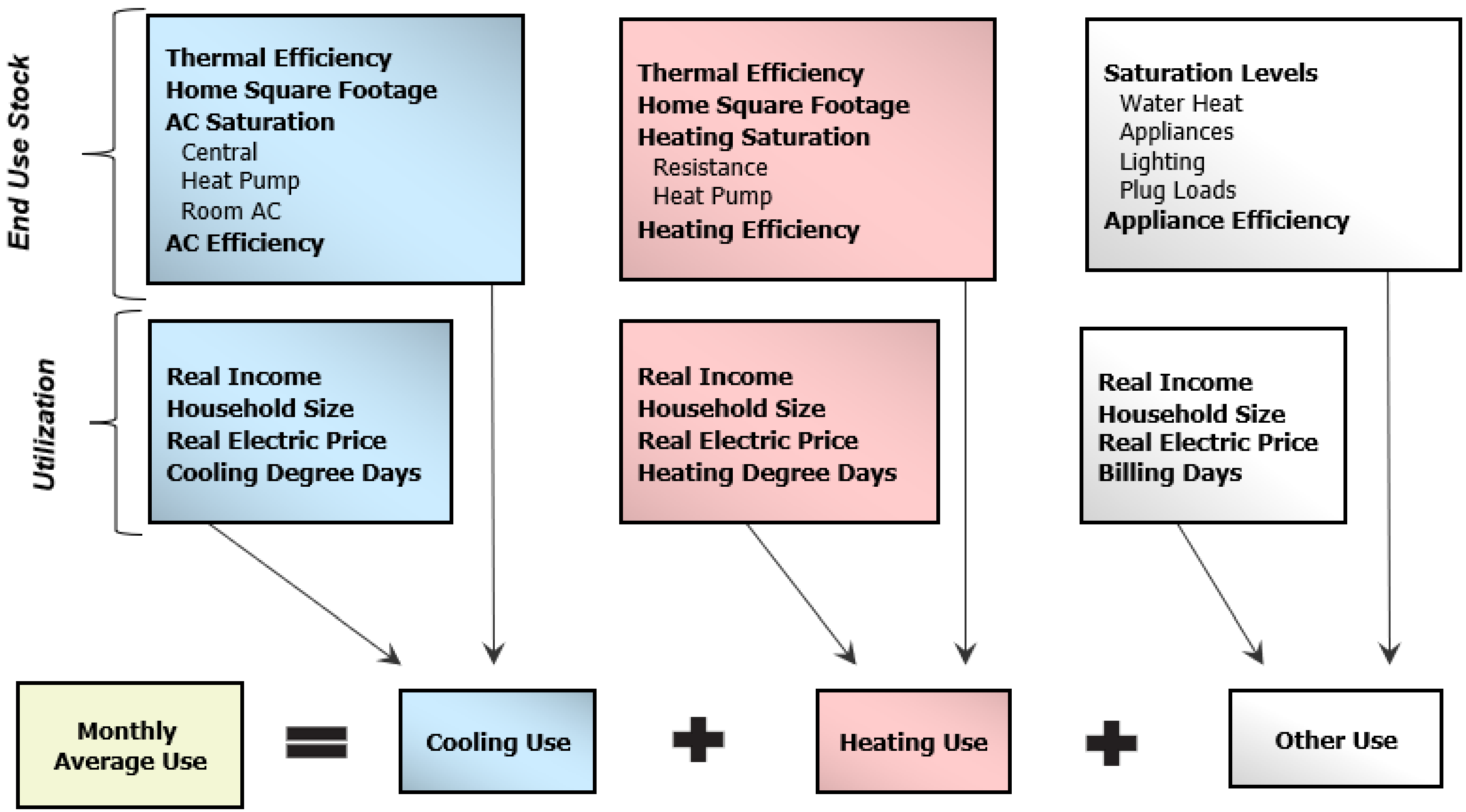


- Average temperature is increasing
  - Trend based on statistical analysis of historical temperature data (1988 to 2021).
  - Average annual temperature increasing 0.5 degrees per decade
  - Decline in HDD (warmer/shorter winters)
  - Increase in CDD (warmer/longer summers)





Residential Average Use model

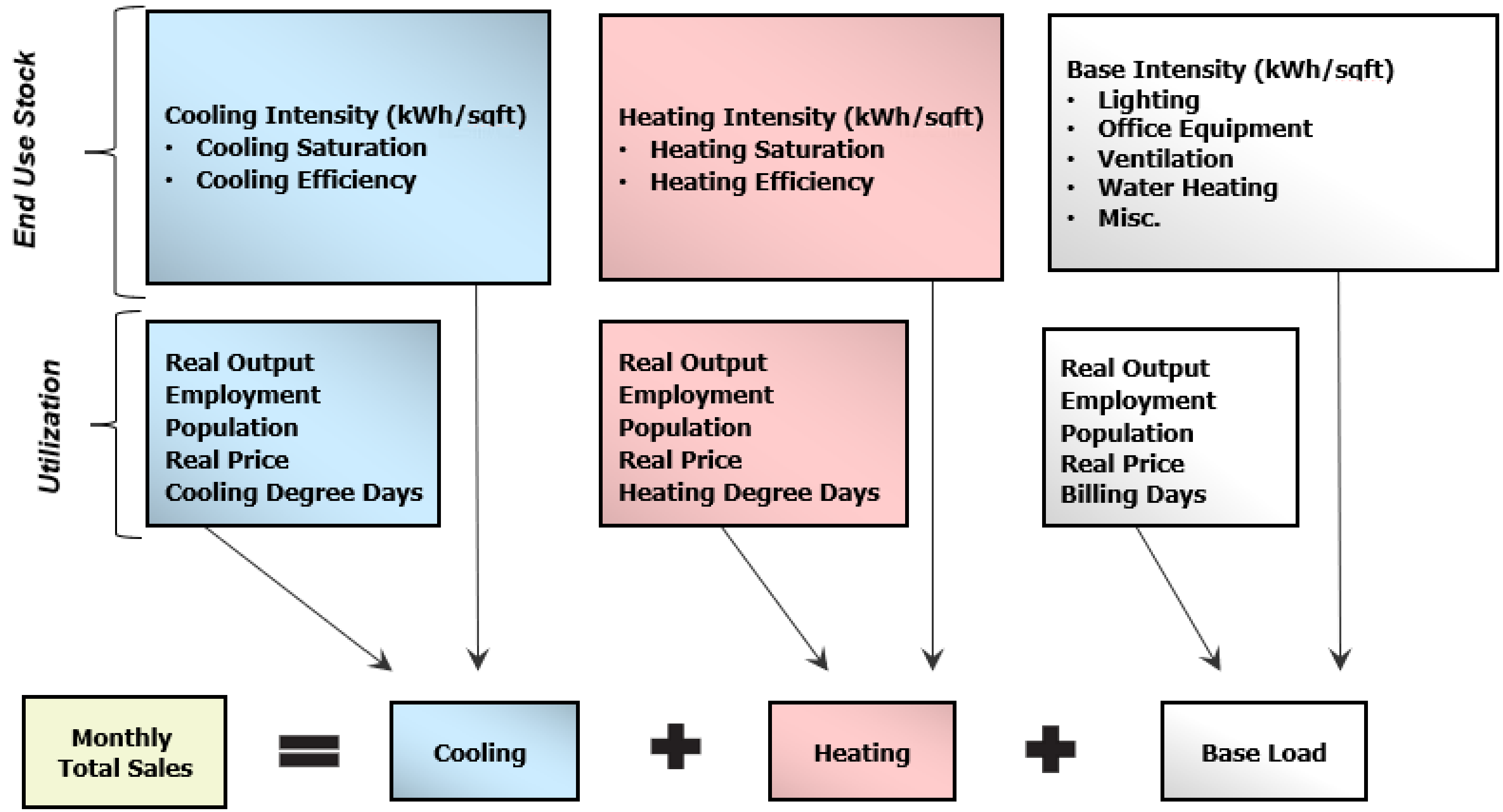


Electric Vehicles and Customer Owned PV Approach

CenterPoint Energy

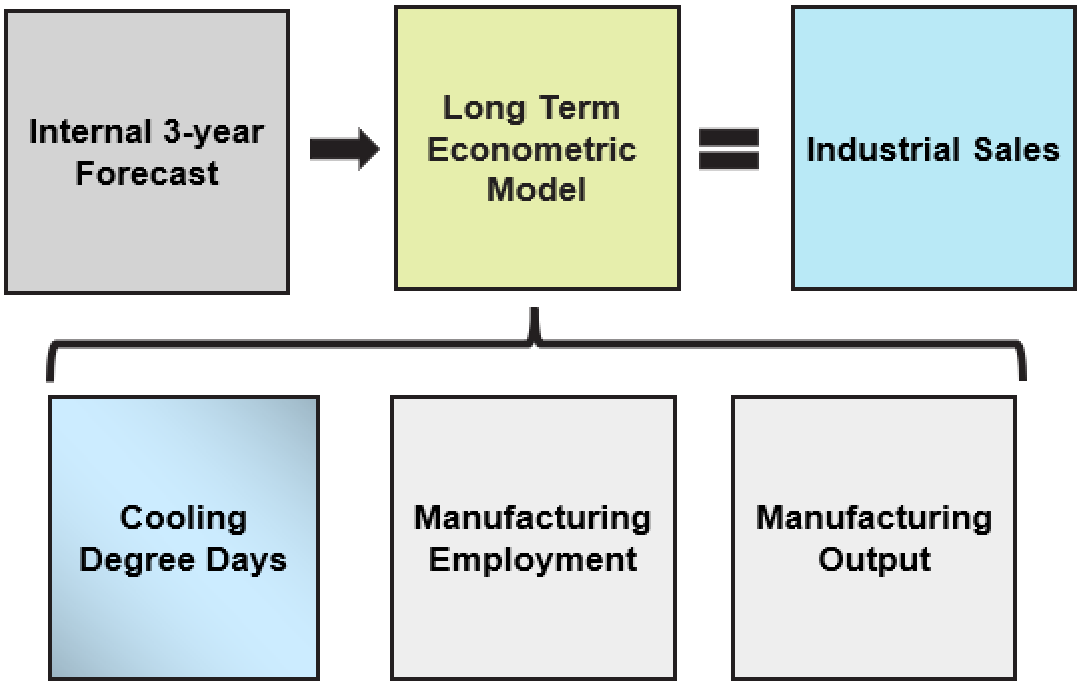
- Energy Information Administration (EIA) forecast based on share of total registered vehicles; Differentiating between all electric (BEV) and plug-in hybrid electric (PHEV)
- Customer economics defined using simple payback
  - Incorporates declining solar system costs, electric price projections, changes in net metering laws, and federal incentives
  - Monthly adoption based on simple payback

Commercial Sales model



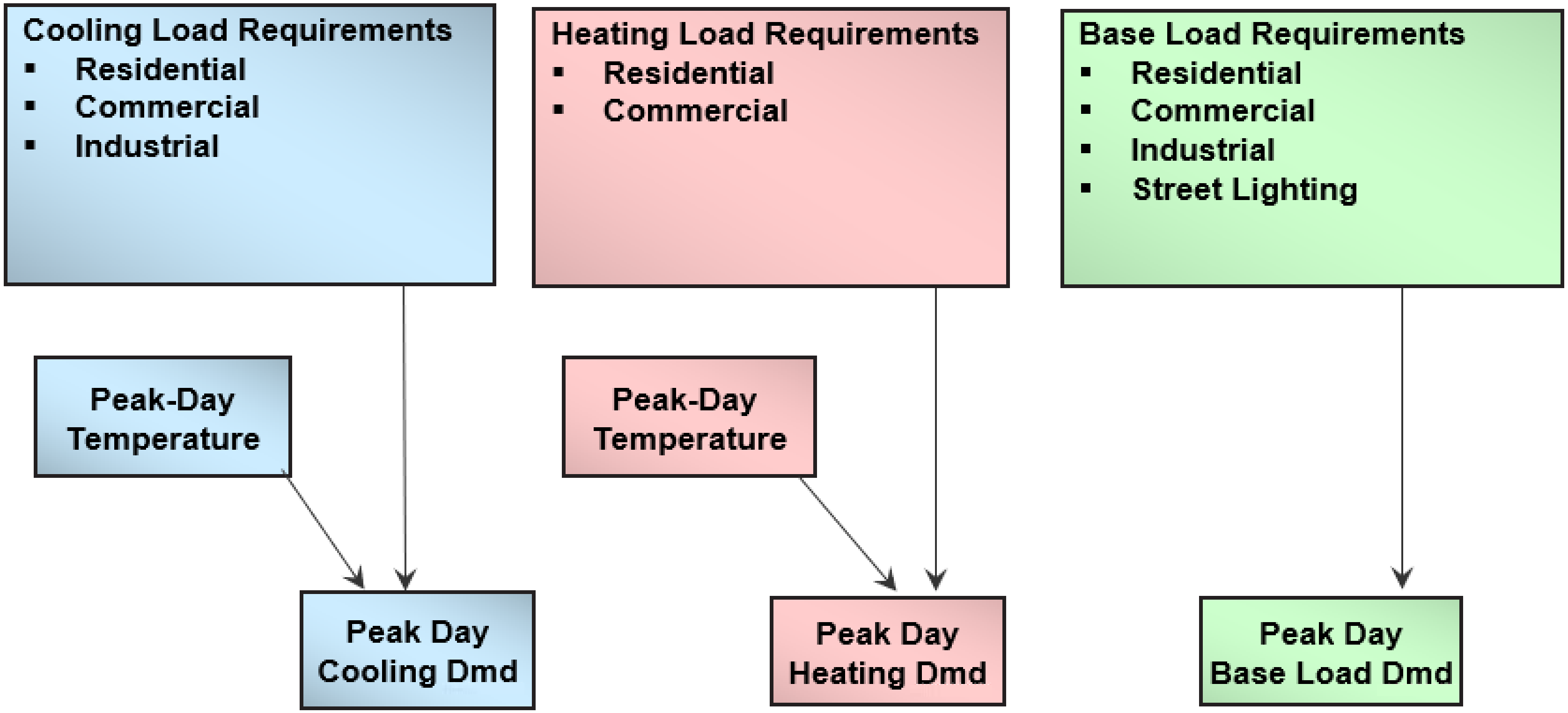
Industrial Forecast

- The industrial (large customer) forecast is a two-step approach
  - The first 3 years is based on Indiana Electric's internal forecast
  - The long-term growth rate is developed using the econometric model framework



Peak Demand Forecast

- Peak demand is driven by heating, cooling, and base load requirements derived from the customer class forecasts



Portfolio Resource Options

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

Existing and Planned Thermal Resources

CenterPoint Energy

Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
A.B. Brown 1	Coal	245	1979	2023
A.B. Brown 2	Coal	245	1986	2023
A.B. Brown 3	Natural Gas	80	1991	N/A
A.B. Brown 4	Natural Gas	80	2002	N/A
F.B. Culley 2	Coal	90	1966	2025
F.B. Culley 3	Coal	270	1973	N/A
Warrick 4	Coal	150	1970	2023 or 2025
OVEC	Coal	32	-	N/A
Blackfoot	Landfill Gas	3	2009	N/A
A.B. Brown 5	Natural Gas	230	2025	N/A
A.B. Brown 6	Natural Gas	230	2025	N/A

Planned

Existing and Planned Non-Thermal Resources

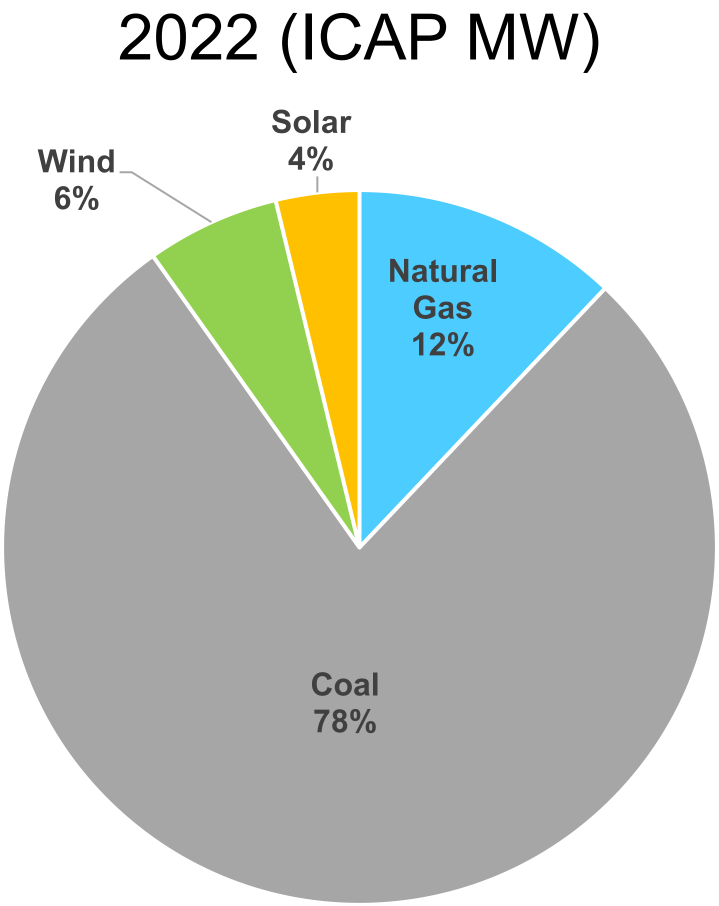
CenterPoint Energy

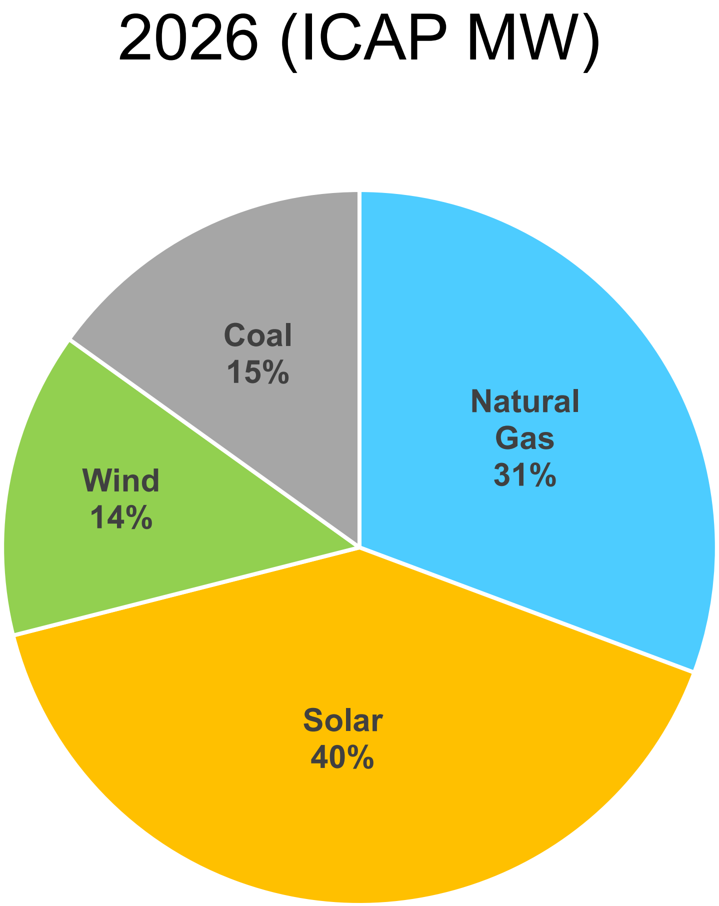
Name	Type	Capacity (MW)	In-Service Date	Retirement / Contract End Date
Benton County	Wind	30	2007	2028
Fowler Ridge	Wind	50	2010	2030
Oakhill	Solar	2	2018	N/A
Volkman Road	Solar\Battery	2\1	2018	N/A
Troy	Solar	50	2021	N/A
Posey	Solar	200	2024	N/A
Vermillion	Solar	185	2024	2038
Wheatland	Solar	150	2024	2044
Rustic Hills	Solar	100	2024	2049
CrossTrack	Solar	130	2025	N/A
Future TBD	Wind	200	2025	N/A

Planned

Existing and Planned Resource Mix

CenterPoint Energy





New Thermal Resources Options

Peaking Natural Gas (~95% Summer & Winter Capacity Accreditation)

- Simple cycle gas turbines
- Reciprocating engines
- F.B. Culley 3 conversion

Combined Cycle Natural Gas (~95% Summer & Winter Capacity Accreditation)

- Fired and unfired
- With and without CCS
- A.B. Brown 5 & 6 conversion

Cogeneration (~95% Summer & Winter Capacity Accreditation)

- Partnership with large industrial customers

Coal (~90% Summer & Winter Capacity Accreditation)

- Supercritical with CCS
- Ultra-supercritical with CCS

Nuclear (~90% Summer & Winter Capacity Accreditation)

- Small modular reactors

New Non-Thermal Resources Options

CenterPoint Energy

Wind (~10% Summer / ~20% Winter Capacity Accreditation*)

- On-shore in northern and southern Indiana
- With and without paired storage

Solar (~50% Summer / ~0% Winter Capacity Accreditation*)

- Utility scale with single axis tracking
- With and without paired storage

Storage (~95% Summer & Winter Capacity Accreditation*)

- Lithium ion (4-hour)
- Long duration (10-hour, compressed air as proxy)

Hydroelectric (To Be Determined)

- At existing Newburgh and J.T. Myers dams on Ohio River

Demand Side

- Energy efficiency
- Demand response

*Accreditation expected to decline over time due to ELCC

Draft Reference Case Inputs and Scenario Discussion

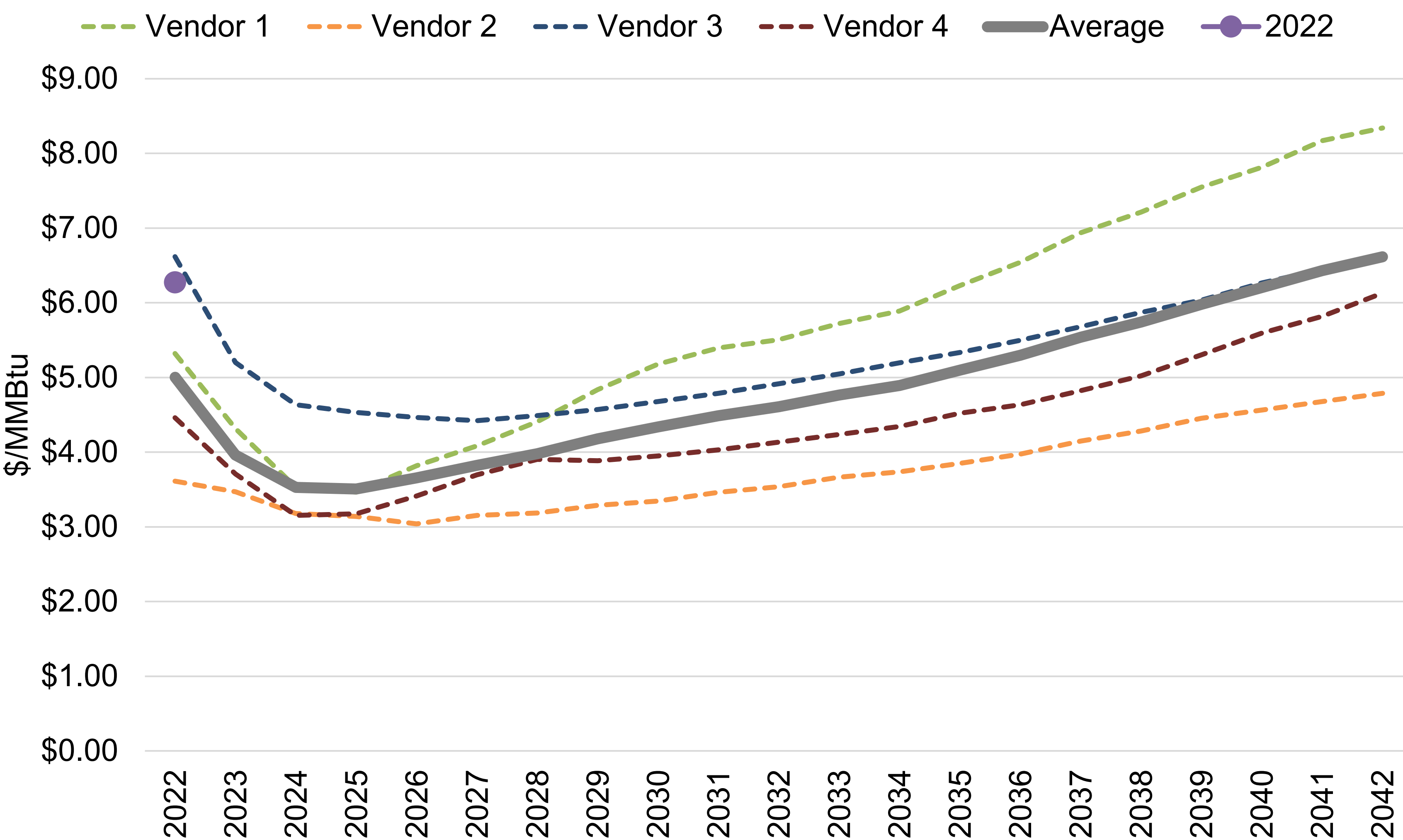
Matt Lind
Director, Resource Planning & Market Assessments
1898 & Co.

Reference Case Inputs

CenterPoint surveyed and incorporated a wide array of sources in developing its Reference Case inputs, which reflect a current consensus view of key drivers in power and fuel markets.

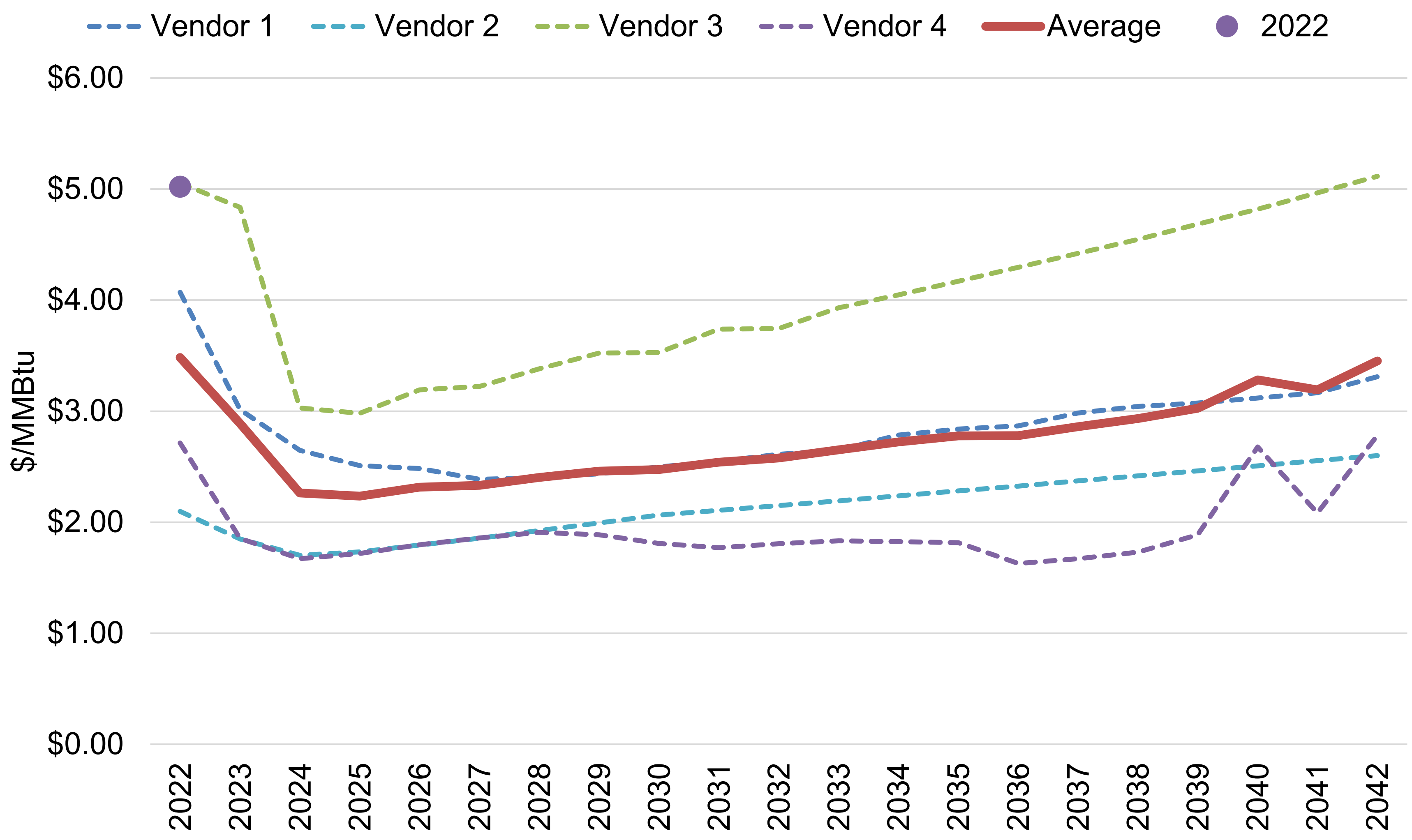
- Reference Case market inputs include forecasts of the following key drivers:
  - Henry Hub and delivered natural gas prices
  - Illinois Basin mine mouth and delivered coal prices
  - MISO Capacity Costs
  - CO_2 ACE Proxy
  - Capital costs for various generation technologies
  - Load forecast
- On- and off-peak power prices are an output of scenario assumptions
- CenterPoint uses a consensus Reference Case view, by averaging forecasts from several sources when available; This ensures that reliance on one forecast or forecaster does not occur

Natural Gas (Henry Hub) Forecast



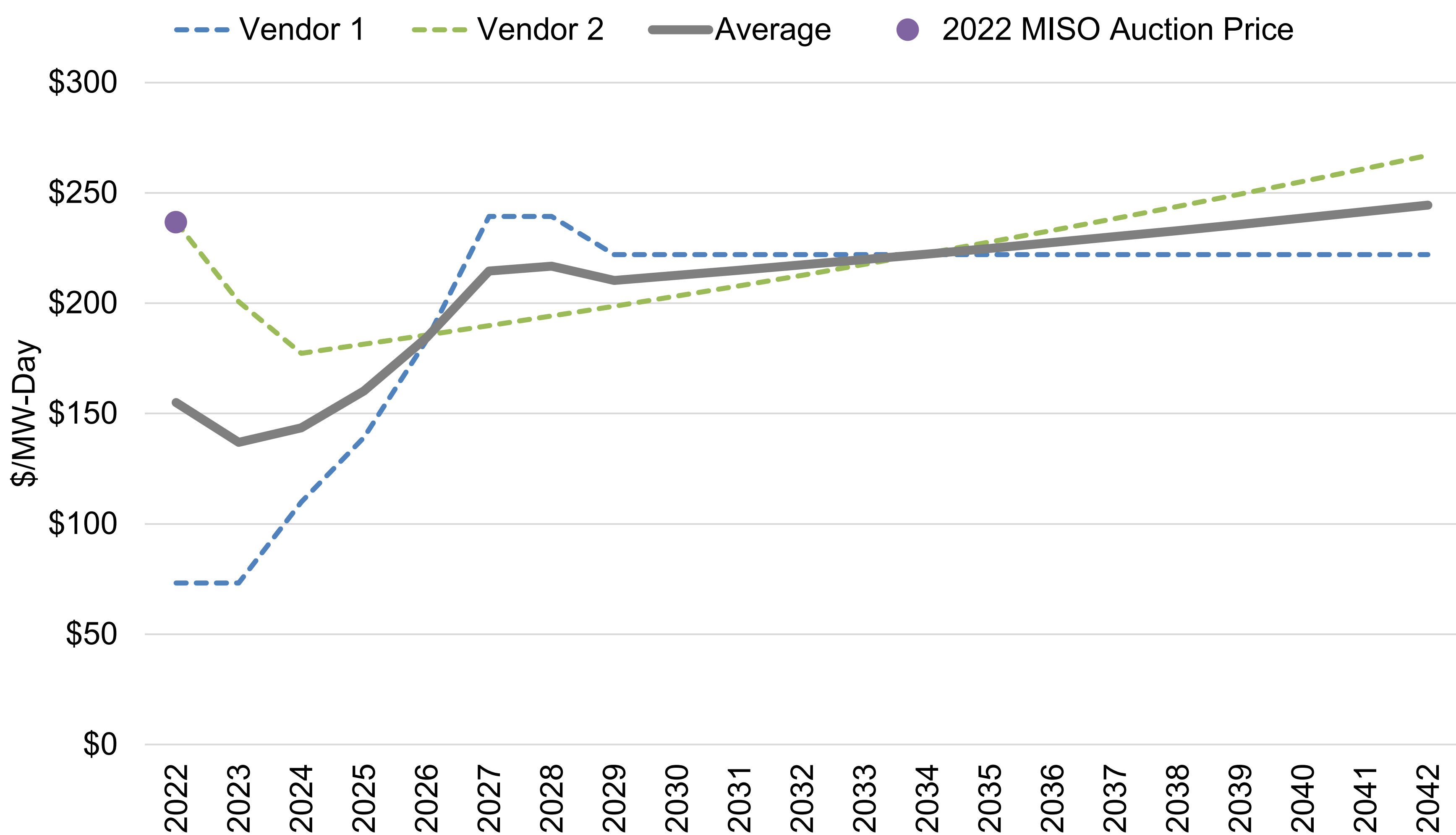
Will be revised as individual forecasts are updated

Coal Forecast



Will be revised as individual forecasts are updated

MISO Capacity Forecast



Will be revised as individual forecasts are updated

Potential Scenarios

CenterPoint Energy

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Reference Case	Base	Base	Base	ACE Proxy	Base	Base	None	None	Base
High Regulatory	↔	↑	↓	↑	↓	↓	Fracking Ban	MATS Update	↑
Market Driven Innovation	↓	↓	↑	↓	↓	↑	None	None	↓
Decarbonization \ Electrification	↑	↔	↑	↑	↔	↔	Methane	None	↓
Continued High Inflation & Supply Chain Issues	↑	↑	↓	↔	↑	↓	None	None	↑

↑ = Higher than Reference Case

↓ = Lower than Reference Case

↔ = Same as Reference Case

Scenario Narratives - High Regulatory – Increased regulations from legislature and government

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
High Regulatory	↔	↑	↓	↑	↓	↓	Fracking Ban	MATS Update	↑

- **Coal** - While there could be regulations that could increase the coal price - demand would be going down, offsetting the increase
- **Natural Gas** – In a high reg environment there will be a ban on fracking which will restrict supply, thus causing gas prices to increase
- **Load** – In high regulatory scenario there is a drag on the economy; Low economic output leads to lower load
- **Carbon** - Legislature passes a high tax on CO_2
- **Renewables and Storage Costs** – Renewables and storage receive increased government incentives reducing their overall cost
- **EE Cost** – Technological innovation is stifled; Lower load leads to less opportunity for cost effective energy efficiency; In addition, a high regulatory environment leads to more codes and standards for equipment; This in turn results in higher incentives for more efficient equipment

Scenario Narratives - Market Driven Innovation – Less government regulation, more free market

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Market Driven Innovation	↓	↓	↑	↓	↓	↑	None	None	↓

- **Coal Price** – Less government influence drives competition among competing fuels for the increase in load
- **Natural Gas Price -** Less government influence drives competition among competing fuels for the increase in load
- **Load** - Less government influence reduces costs, which drives increased usage
- **Carbon** - No carbon tax nor ACE like requirements
- **Renewables and Storage Costs** – Increased demand for renewable and storage resource options spurs further technological innovation to lowers cost
- **EE Cost** – Technological innovation drives more opportunities for EE programs; Increased load drives more opportunity for cost effective energy efficiency; Less codes and standards changes will allow utility sponsored EE programs more opportunities to transform the market at a lower incentive cost

Scenario Narratives - Decarbonization\Electrification

– Consumers are moving to electrify transportation and promotes fuel switching in homes and businesses from natural gas to electricity

CenterPoint Energy

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Decarbonization \ Electrification	⇧	⇔	⇧	⇧	⇔	⇔	Methane	None	⇩

- **Coal Price** – Demand for coal decreases as a mid level carbon tax is imposed, supply is constrained causing price to increase
- **Natural Gas Price** – Methane regulation causes the cost of gas to increase but is offset by increased supply due to fuel switching away from natural gas heating
- **Load** – Increased due to fuel switching while economy remains at reference levels
- **Carbon** - Mid level carbon tax imposed
- **Renewables and Storage Costs** – Technological improvements which typically lowers costs are offset by higher demand and rising land and labor costs
- **EE Cost** – Increased load allows more opportunities for EE potential and reduces the cost of EE acquisition; Further, a carbon tax will allow for more cost-effective EE measures

Scenario Narratives - Continued High Inflation & Supply Chain Issues

CenterPoint Energy

	Coal Price	Natural Gas Price	Load	Carbon	Renewables and Storage Cost	Economy	Gas Regulation	Other Environmental Regulations	EE Cost
Continued High Inflation & Supply Chain Issues	↑	↑	↓	↔	↑	↓	None	None	↑

- **Coal Price** – Increased costs for delivery and labor with reduced supply drive coal prices higher
- **Natural Gas** – Less new drilling leads to reduced supply and increased demand, resulting in higher cost
- **Load** – High inflation reduces economic output, reducing load demand
- **Carbon -** Reference
- **Renewables and Storage Costs** – Continued disruption in supply chain partnered with high inflation shows continued high cost for renewables and storage
- **EE Cost** – Reduction in load results in less potential and higher cost of EE acquisition both for incentives passed to customers and implementation of programs as implementers experience increased cost; Shortage of EE equipment leads to increased cost of high-efficient measures

Q&A

Appendix

Definitions

Term	Definition
ACE	Affordable Clean Energy (ACE) Rule, establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants
All-Source RFP	Request for proposals, regardless of source (renewable, thermal, storage, demand response)
BAGS	Broadway Avenue Gas Turbine
BTA	Build Transfer Agreement/Utility Ownership
C&I	Commercial and Industrial
CAA	Clean Air Act
CAGR	Compound Annual Growth Rate
Capacity	The maximum output of electricity that a generator can produce under ideal conditions (megawatts)
CCGT	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50 percent more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power
CCR Rule	Coal Combustion Residuals Rule
CCS	Carbon Capture and Storage
CDD	Cooling Degree Day
CEI South	CenterPoint Energy Indiana South
CO_2	Carbon dioxide

Definitions Cont.

Term	Definition
CONE	Cost of New Entry
CPCN	A Certificate of Public Convenience and Necessity is required to be granted by the Commission for significant generation projects
CSAPR	Cross State Air Pollution Rule
DER	Distributed Energy Resource
Deterministic Modeling	Simulated dispatch of a portfolio in a determined future. Often computer generated portfolios are created by optimizing on cost to the customer
DLC	Direct Load Control
DR	Demand Response
DSM	Demand side management includes both Energy Efficiency and Demand Response programs to reduce customer demand for electricity
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines are U.S. national standards for wastewater discharges to surface waters and publicly owned treatment works
EnCompass	Electric modeling forecasting and analysis software
Energy	Amount of electricity (megawatt-hours) produced over a specific time period

Definitions Cont.

Term	Definition
EPA	Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
GW	Gigawatt (1,000 million watt), unit of electric power
GWh	Gigawatt Hour
HDD	Heating Degree Day
Henry Hub	Point of interconnection of interstate and intrastate natural gas pipelines as well as other related infrastructure in Erath, Louisiana
IDEM	Indiana Department of Environmental Management
Installed Capacity (ICAP)	Refers to generating capacity after ambient weather adjustments and before forced outages adjustments
Intermittent	An intermittent energy source is any source of energy that is not continuously available for conversion into electricity and outside direct control
IRP	Integrated Resource Plan is a comprehensive plan to meet customer load expectations
IURC	The Indiana Utility Regulatory Commission is the public utilities commission of the State of Indiana. The commission regulates electric, natural gas, telecommunications, steam, water and sewer utilities
KWh	Kilowatt Hour

Definitions Cont.

Term	Definition
LCOE	Levelized Cost of Energy, A measure that looks at cost and energy production over the life of an asset so different resources can be compared. Does not account for capacity value.
LMR	Load Modifying Resource
Local Clearing Requirement (LCR)	Capacity needs to be fulfilled by local resource zone
LRZ6	MISO Local Resource Zone 6
MATS	Mercury and Air Toxics Standard
Mine Mouth	At the mine location
MISO	Midcontinent Independent System Operator, an Independent System Operator (ISO) and Regional Transmission Organization(RTO) providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest United States and Manitoba, Canada and a southern United States region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets
MMBTU	Million British Thermal Units
MPS	Market potential study - Determines the total market size (value/volume) for a DSM at a given period of time
MSA	Metropolitan Statistical Area
MW	Megawatt (million watt), unit of electric power
NAAQS	National Ambient Air Quality Standards

Definitions Cont.

Term	Definition
Name Plate Capacity	The intended full-load sustained output of a generation facility
NDA	Non-Disclosure Agreement
NOI	Notice of Intent
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPVRR	Net Present Value Revenue Requirement
NSPS	New Source Performance Standards
OMS	Organization of MISO States, was established to represent the collective interests of state and local utility regulators in the Midcontinent Independent System Operator (MISO) region and facilitate informed and efficient participation in related issues.
Peaking	Power plants that generally run only when there is a high demand, known as peak demand, for electricity
Planning Reserve Margin Requirement (PRMR)	Total capacity obligation each load serving entity needs to meet
Portfolio	A group of resources to meet customer load
PPA	Purchase Power Agreement

Definitions Cont.

Term	Definition
Preferred Portfolio	The IRP rule requires that utilities select the portfolio that performs the best, with consideration for cost, risk, reliability, and sustainability
Probabilistic modeling	Simulate dispatch of portfolios for a number of randomly generated potential future states, capturing performance measures
PV	Photovoltaic
RA (Resource Adequacy)	RA is a regulatory construct developed to ensure that there will be sufficient resources available to serve electric demand under all but the most extreme conditions
RAP	Realistic Achievable Potential
Resource	Supply side (generation) or demand side (Energy Efficiency, Demand Response, Load Shifting programs) to meet planning reserve margin requirements
SAC	Seasonal Accredited Capacity
Scenario	Potential future State-of-the-World designed to test portfolio performance in key risk areas important to management and stakeholders alike
SDE	Spray Dryer Evaporator
Sensitivity Analysis	Analysis to determine what risk factors portfolios are most sensitive to
SIP	State Implementation Plan
Spinning Reserve	Generation that is online and can quickly respond to changes in system load

Definitions Cont.

Term	Definition
T&D	Transmission and Distribution
Technology Assessment	An analysis that provides overnight and all-in costs and technical specifications for generation and storage resources
Unforced Capacity (UCAP)	A unit’s generating capacity adjusted down for forced outage rates (thermal resources) or expected output during peak load (intermittent resources)
VAR Support	Unit by which reactive power is expressed in an AC electric power system
ZLD	Zero Liquid Discharge

CenterPoint 2022 IRP
1st Stakeholder Meeting Minutes Q&A
August 18, 2022, 9:30 am – 3:30 pm CDT

Richard Leger (Senior Vice President, CenterPoint Energy) – Welcome, Safety Message, Introduction to CenterPoint Energy, Personal background and CenterPoint team introductions, Updates and Goals for this 2022/2023 IRP

Matt Rice (Director, Regulatory and Rates, CenterPoint Energy) – Discussed the meeting agenda, guidelines for the meeting, discussed directors report feedback, and the proposed 2022/2023 IRP and stakeholder process.

- Slide 5 Generation Transition Timeline:
  - Question: I noticed the retirement date for Culley 2 has changed from 2023 to 2025.
    - Response: Over the last year, capacity market prices in MISO have increased significantly. To keep that capacity value for a plant that doesn't run a lot, we decided to extend it for 2 years.
  - Follow-up: You may extend the agreement with Warrick 4 from 2023 to 2025?
    - Response: We do not have an agreement that runs past 2023 currently.
  - Question: Are you planning to evaluate the cost of the CTs compared to another alternative based on the new federal tax credit in the IRA?
    - We intend to move forward with the CTs. We have the approval from the IURC and are awaiting approval from FERC to move forward.
- Slide 12 2022/2023 Stakeholder Process:
  - Question: Final modeling results will not be done by March 31st. There is a wide gap between the last stakeholder meeting on March 14th and the filing date [June 1, 2023]. Can the portfolio change between those two dates? I'm worried modeling results based on the dates posted might not be done before the final meeting.
    - Response: We don't expect any changes to the portfolio. It takes time to do the analysis and get thoughts on paper. We plan to share the modeling results as soon as possible.
- General Section Questions:
  - Question: What percentage of the Cully ELG compliance work has been completed?
    - Response: It will be in service by March 1st of next year. Probably over 50%.
  - Correction by CenterPoint: Correction. We are negotiating for wind. We currently have not filed for wind, but plan to file in the very near future.

Matt Lind (Director, Resource Planning & Market Assessments. 1898 & Co.) – Discussed Objectives & Measures and gathered stakeholder feedback.

- Slide 16 IRP Draft Objectives and Measures:
  - Question: On your slide, you said measured in carbon dioxide. How will that be measured just CO_2 or CO_2 equivalent?
    - Response: Yes CO_2 and CO_2 equivalents are two possible metrics. Last time we used life cycle CO_2 emissions but the results were very similar to just tons of output so we have decided to move away from life cycle emissions.
  - Question: If the CO_2 intensity is similar to absolute tons of CO_2, why are you changing that metric? Is the appropriate measure not the total tons of CO_2 emitted into the environment?
    - Response: There is an absolute value, the metric was chosen based on intensity as we have different load demand assumptions in a particular portfolio. But that is good feedback and something that we will take into consideration.
  - Question: Are you going to measure thermal accreditation on a UCAP basis or are you going to attempt to translate the seasonal accreditation methodology into the accredited value of your thermal units?
    - Response: It is something we will look at, consider, and evaluate. We do intend to accredit all resources, thermal and otherwise, on a seasonal basis.
- General Section Questions:
  - Question: Will demand response be a part of the portfolio plans? Will CenterPoint expand DR to commercial customers?

- Response: Demand response will be discussed in further detail as we move forward in the process. We are looking at a combination of direct load control and rate programs. This allows us to have customers control different rates at different periods of time. We are looking to fully transitioned to smart thermostats by 2029.
- Question: What are your plans if FERC doesn't approve the [natural gas] pipeline [needed for the new CTs]?
  - Response: All portfolios assume future FERC approval. If it is not approved, we will refer to the IRP process to guide us in the next steps. The plan is to move forward with the CTs.
- Question: Is the CT totally dependent on that gas pipeline being approved?
  - Response: There is not enough gas at the site today. We will need the gas pipeline for the CTs to operate. There is a lot of other equipment at that site, such as the substation and the interconnect rights, that make that site favorable for the CTs.
- Question: What are the new and different technologies in the future coming beyond what we already have?
  - Response: Some of the future technologies both on the demand and supply side will be touched on later in this presentation. The technology mentioned is new in terms of the impact it will have to the supply side. Not necessarily that the technology itself is new.

Kyle Combes (Project Manager, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the 2022 IRP modeling software, EnCompass.

- Slide 19 What are Encompass' Capabilities?
  - Question: Can Encompass model other types of storage beyond chemical storage (e.g., battery)?
    - Response: Yes. It's not specific to just chemical battery storage. Other options may be modeled with the correct input assumptions. Variable costs, capital costs, etc.
  - Follow-Up: Why did the CAC suggest switching to EnCompass?
    - CAC Response: We have some experience licensing several other software's used by MISO. We found that if you are looking at someone else's modeling files, it is important you can digest those modeling files, and understand the constraints to those inputs. Encompass models can be input and exported in an Excel format. Several other models don't have that capability. 1898 and Co. also licenses Encompass, so it was beneficial to use that as the modeling software.
  - Question: Can you compare the gas plant cost to the other technologies mentioned this morning?
    - Response: Based on comments and discussion today, yes, the CTs have been approved and will be part of the plan for the CenterPoint portfolio. We did not suggest that the CTs be built in an alternate location.
- General Section Question:
  - Question: If the modeling files are available in advance, can they be seen earlier by those who have signed the NDA?
    - Response: We will take that into consideration and provide those as soon as we can. [The expected data release schedule is on slide 10.]
  - Question: I would like to formally request that you run the portfolio without the gas turbine to determine least cost.
    - Response: The request has been noted.
  - Question: Why don't you go ahead and evaluate the cost now without the CTs, so you don't have to rerun the evaluation?
    - Response: We will take that into consideration. We should have an answer from FERC later this year [or early next year] regarding the pipeline.

Drew Burczyk (Consultant, Resource Planning & Market Assessments, 1898 & Co.) – Discussed the Request For Proposals (RFP) methodology, scoring, role, and provided high level statistics for CenterPoint's RFP.

- Slide 26 Preliminary RFP Statistics:
  - Question: Would you be getting updated numbers on the people that bid solar?
    - Response: We are still digesting the information to see how the bill [Inflation Reduction Act] impacts our current plan. By the second stakeholder meeting we should have more clarity on how the bill impacts pricing.
  - Question: How will the bids be incorporated into the IRP modeling? And do you know yet how/if they will be used as the basis for future costs?

- Response: We will have the cost curve assumptions ready for the next stakeholder meeting. We do have RFP responses to use as a reference for the next few years to use in IRP modeling.
  - Question: Are you surprised on the breakdown percentage for RFP bids (especially storage)?
    - Response: We are not surprised by the type of bids we have received. Over the last few RFP's, there have been more storage projects in the MISO interconnection queue, so it makes sense that we would be seeing more storage proposals now.
  - Question: Is the nuclear capacity existing or new build?
    - Response: The nuclear bid is an existing resource.
- General Section Questions:
  - Question: Given the IRA is offering both PTC and ITC which includes storage, when looking at the modeling, will you be assuming the 30-40% cost savings in certain communities outlined in the act?
    - Response: We are still processing the potential impacts of the new legislation. We will have more clarity in the next meeting on how we plan to account for those updates.
  - Question: Will we be able to access the bids for those of us with NDAs?
    - Response: Yes, the plan is to follow a similar process as the 2019 All-Source RFP.
  - Question: In Encompass, are you planning to model renewables as a project or as a resource?
    - Response: We haven't decided on any of the modeling just yet. Any input or feedback that you may provide, we will consider.

Matt Lind – Discussed MISO Updates, Resource Adequacy and key functions, and updates for FERC 2222.

- Slide 34 MISO Zone 6 Capacity Prices:
  - Question: Can you expand on the MISO capacity chart?
    - Response: The chart shows historical numbers of the MISO capacity auction and for the current planning year. The chart shows the historical clearing prices, or the price of capacity purchased specifically for MISO zone 6. The capacity price is associated closely with the demand at that time i.e., market driven. High prices reveal the need to add more capacity to the market.
  - Question: These Peaker plants seem large for the local need. Would CenterPoint be a provider to the grid during these times of high prices? Who would benefit from these high prices, the customers, or the company?
    - Response: This is a capacity price, not a function of energy sales. The CTs were added to meet CenterPoint's own capacity needs, not necessarily to sell into the market as surplus. Different resources and technology types have different characteristics. Seasonally, we look at how those technologies perform in different conditions. Every technology type will receive its own capacity credits, and CenterPoint must meet that capacity demand in all conditions.
- General MISO Questions:
  - Question: In terms of the FERC 2222, do you all have a sense of an approach that you would like to take or are likely to take? Is the question about the adoption rate of those technologies or is it about the things that CenterPoint would do internally to promote the adoption of those technologies and the tradeoffs of those approaches?
    - Response: Ultimately, it's projecting the adoption rates of those technologies and the impact on the load forecasts. The impact of the adoption on portfolios considering how quickly those will come into effect and how quickly the demand will have to be met with those resources coming online. Thoughts and feedback are welcome.
  - Question: Does the model have capabilities to model the FERC 2222?
    - Response: We can see it possibly affecting the load forecasts. We could model the impact based on different assumptions.
  - Question: I wanted to bring attention to an article on vertical solar panels that are bi-facial. They require less battery storage and capture electricity for long periods of the day. Just wanted to bring it up and have CenterPoint look at it as an option.
    - Response: Please send the article to irp@centerpointenergy.com

Scott Duhon (Director, Environmental Compliance & Policy, CenterPoint Energy) – Discussed environmental regulations and policy.

- Slide 41 NO_X Ozone Season Allowances:
  - Question: To calculate how much it would cost to comply with this, would you just multiply the tons purchased by the purchased cost per allowance?
    - Response: Yes.
  - Follow-Up: For 2022, we're looking at over $22M for NOx compliance?
    - Response: As you can see, as time has gone on, allowances allocated to CenterPoint have gone from 1,381 to 851. We have used our selective catalytic reduction equipment to reduce NOx as much as we can without causing other operational issues. With the high capacity factor this year, we project to be about 450 tons short on these NOx allowances. There is a short supply on the market. It is very expensive to purchase NOx allowances in the market.
  - Question: What does high costs of NOx mean regarding keeping Culley 2 online an extra 2 years?
    - Response: Regarding Culley 2, the unit doesn't run a lot due to the high costs. We will extend it through 2025 because we can hold it for capacity which limits the amount of capacity we have to buy on the market. This will help us reduce the cost to customers.
  - Question: Is there anything being done to hedge the cost of NOx allowance purchases? What is being done to reevaluate the cost of these units?
    - Response: To mitigate NOx emissions, we are injecting as much ammonia into our selective catalytic system. Additionally, when bidding these units into the market, accounting for the NOx price is included in our offer price.
  - Follow-Up: How are you currently recovering those allowance costs? Are those tracked and/or embedded in rates?
    - Response: The costs get recovered through the RCRA once a year.
- General Section Questions:
  - Question: Can carbon emissions be also measured in their absolute tonnage?
    - Response: CenterPoint looks at absolute tonnage.
  - Follow-Up: On your website, it says that you take the Paris commitment under serious consideration. Is it talking about carbon intensity, absolute tonnage emissions, or what? Is this part of the planning that you use?
    - Response: When we look at net zero, we look at absolute tonnage. We have modeled the retirement of all coal by 2035. This is an assumption. Since we are moving from coal to primarily renewables, most of the offsets aren't going to the generation side. We aren't anticipating significant need for offsets to the generation emissions.
  - Question: Do the combustion turbines have lower NOx than the coal units?
    - Response: Yes.
  - Question: What is the current retirement on Culley 3?
    - Response: This will be evaluated through the IRP.

Jeffery Huber (Principal, Energy Efficiency, GDS Associates, Inc.) – Discussed Market Potential Studies, Energy Efficiency and Demand response.

- Slide 54 DR Analysis – Programs Included
  - Question: Does CenterPoint have any Demand response programs for residential customers?
    - Response: We do have the legacy smart saver switches. We have a couple of residential demand response programs such as the legacy direct load control program. In 2016, we implemented a pilot program and rolled that out into a smart thermostat program. The goal is to phase out the load control program and ramp up the "bring your own thermostat" program.
  - Follow Up: Recommends implementing residential rate programs [critical peak pricing, TOU, etc.] sooner. Haven't you rolled out the smart meter program?
    - Response: In terms of AMI systems, the meters are out in the field. We are working on incorporating the legacy meter data management system into the CenterPoint system. The system is not ready yet.
- General Section Questions:
  - Question: In the future, will CenterPoint allow users to participate in the program without pre-cooling their home?

- Response: The intent with the pre-cooling option is to make the customer more comfortable prior to a demand response event. The pre-cooling is only available with certain brands of thermostat.
  - Question: When you are looking at the achievable market share for energy efficiency, would you consider 50-100% rebates on appliance upgrades? Will that impact overall effectiveness and adoption?
    - Response: The analysis was done prior to the IRA passing. The low to moderate income rebates could be affected. We generally model them with high incentives. In the past when there have been similar types of tax credits, we have modeled them in a similar way.
  - Question: How do you determine these incentives?
    - Response: We did research that looked at customers' willingness to participate at certain levels. That research asked customers, both residential and non-residential, what their likelihood would be to participate in this program. We are in the process of evaluating the demand response incentives to get as much participation as possible.

Michael Russo (Senior Forecast Consultant, Itron) – Discussed historical trends, economic drivers, industry trends, and portfolio forecasts.

- Slide 63 End-use Intensity trends:
  - Question: How were you able to determine an increase in the forecast of energy intensity in the residential sector?
    - Response: The total decline in energy intensity from 2010 to now has been in lighting. In the energy outlook in 2022, there were no major improvements in end use efficiency that would change the graph.
- Slide 64 Electricity Prices:
  - Question: Regarding electricity prices, does it matter what the absolute rate is, or does it just matter what the rate of change is? How elastic is demand to price?
    - Response: For the regression model, the important factor is the percent change. Electricity is inelastic: people don't respond that much to changes in electricity prices.
- General Section Questions:
  - Question: Can you help me square the fact that residential use has been declining over time, but intensity appears to be increasing over time?
    - Response: One of the major savings from 2010 until now has been lighting. Lighting is at its lowest point basically now. The one end use that is increasing is the misc. category.

Kyle Combes – Discussed portfolio resource options, both new and existing.

- General Section Questions:
  - Question: Can you talk more about a conversion from CTs to CC? Would that require another Certificate of public convenience and necessity (CPCN)?
    - Response: Yes. The CTs would be the same. You could add heat recovery steam generators. Peaking gas turbines are mainly a capacity resource with a less efficient heat rate, but less expensive on capital investment. Yes, it would require another CPCN.
  - Follow-Up: Why would you pursue a new joint agreement until 2025 for Warrick?
    - Response: We are short on capacity in the 2024/2025 planning year [until the CTs come online]. Our customers will be vulnerable to the capacity price at that time. If we can reach a fair agreement, we can avoid paying for capacity until some of those other units come online, and ultimately, save our customers money.
  - Question: Is this a pre-screening list or the post-screening? Does this mean that new coal passed the screening?
    - Response: No pre-screening has been done at this time. We have not determined if we will do a LCOE or other pre-screening at this time. Usually we would only pre-screen in specific technology groups where there are multiple options, if there were several different peaking gas technologies for example.

Matt Lind – Discussed reference case inputs and scenarios.

- Slide 80 Natural Gas (Henry Hub) Forecast:

- Question: Based on an internet search, the Henry Hub natural gas price today is $9.23/MMBtu. The graph does not reflect this number. Can you explain?
  - Response: The pricing is the 2022 average [consistent with the annual datasets shown]. It is not today's Henry Hub pricing.
- Question: Are the graphs nominal or real?
  - Response: The forecasts are in nominal dollars.
- Question: Expressed concern about forecasts.
  - Response: We are living in a volatile time from normal gas pricing. Going back 10-15 years prices were in the $8/MMBtu range. We have seen price fluctuations before, and there is uncertainty in the price assumption [as with most forecasts today]. We will do a probabilistic stochastic analysis to capture volatility, [and we will update with vendor forecasts as they are updated.]

<u>Open Q&A Session</u>

- Question: Does CenterPoint want to add fuel risk as an objective and measure?
  - Response: NPV largely captures fuel cost and risk inherent to a portfolio. We will consider it.
- Question: What is the implication of the economy assumption for the modeling?
  - Response: The assumption is not a direct input into the model, the economy assumption indirectly or directly effects other metrics across the scenario. But generally, load for example is one that is more directly correlated to the economy.
- Follow-Up: What tool are you using for modeling assumptions?
  - Assumptions will be modeled similar to previous IRPs.
- Question: How much is the new law going to impact the new modeling relative to methane gas?
  - Response: We will be looking into the impacts of the new legislation and provide updates in future scenarios.
- Question: Can we start the process of sharing data to make an interactive process?
  - Response: We will take the feedback into consideration moving forward.
- Question: Do you plan to talk about the metrics at the next meeting or are those decided?
  - Response: We've heard feedback on carbon intensity and other metrics, so we will go back and reassess.

Comments of CAC on CenterPoint's First 2022-2023 IRP Stakeholder Workshop

Submitted to CenterPoint on September 1, 2022

Citizens Action Coalition of Indiana ("CAC") submits these comments on the materials presented and issues discussed during CenterPoint's August 18, 2022, Integrated Resource Plan ("IRP") stakeholder workshop.

1 General Stakeholder Process

CAC appreciates CenterPoint's "Commitments for 2022/2023 IRP." We look forward to working constructively with CenterPoint throughout this process to achieve an IRP that will provide beneficial outcomes to CenterPoint's customers.

Thank you for agreeing to facilitate technical workshops with stakeholders like CAC that execute non-disclosure agreements ("NDAs"). CAC also appreciates the schedule shared by CenterPoint that includes time tables for sharing information with stakeholders at regular intervals throughout the process.

CAC would also like to request that CenterPoint:

- Provide to CAC the full bid proposals received in response to its 2022 request for proposals at its earliest convenience.
- Use an online data sharing platform (e.g., Drop Box, Sharefile, etc.) to provide IRP data files to stakeholders who have executed NDAs.
- Provide direct and clear responses to stakeholder input, such as through additional calls or as part of the technical conferences, so that stakeholders can have an understanding of how their feedback was considered.
- Commit to providing its data inputs and modeling files to stakeholders on a schedule that permits stakeholders to provide feedback and gives CenterPoint sufficient time to be able to incorporate that feedback.

2 Objectives and Measures

CAC thanks CenterPoint for providing these draft metrics early in the process to allow time for stakeholder input and response. CAC has the following concerns and recommendations about the draft Objectives and Measures identified by CenterPoint:

- **Environmental Sustainability:** Best practice is to use total (absolute) CO_2-equivalent emissions, not CO_2 intensity, as the metric for measuring impacts to climate. CO_2 intensity does not indicate whether greenhouse gas ("GHG") emissions are increasing or decreasing. Total GHGs – not the rate of GHG emissions – is what is causing harm to the climate system. If the rationale for using intensity is the ability to compare the electrification portfolios, there are at least two options available to address that concern. One is to enforce an emissions reduction constraint in any electrification based portfolio so that total emissions drop even as load is increased. This would be consistent with the rationale for the electrification – to reduce carbon emissions. Another option is to evaluate the electrification portfolios only against each other. <u>CAC strongly recommends using cumulative CO_2-equivalent emissions over the IRP period as the measure for the Environmental Sustainability objective.</u>

- **Fuel Price Risk:** CAC believes none of the identified metrics would sufficiently measure the risk of different portfolio options to CenterPoint's customers associated with fuel price volatility. Since CenterPoint passes through all fuel costs to its customers, the risk of fuel price spikes is borne entirely by the customer. Therefore, it is critically important that CenterPoint evaluate how various portfolio options compare on the amount of fuel price risk associated with the selected resources. Portfolios that rely more on meeting customer energy needs using technologies that rely on volatile fuel prices are riskier to customers than portfolios that rely less on fuels that have volatile costs. <u>CAC recommends that CenterPoint adopt a Rate Stability objective with three metrics (cost certainty, cost risk, and lower cost opportunity) that NIPSCO used in its most recent IRP</u>. In the alternative, CenterPoint could adopt a "Fuel Price Risk" objective with an associated measure of "Proportion of annual energy generated by resources that rely on fuels that have volatile costs," where fuels with volatile costs includes both coal and natural gas.

- **Reliability:** CAC wishes to better understand what objective CenterPoint will set for this metric and how it will assign "Spinning Reserve/Fast Start Capability" to resources. The stated measure is "% of Portfolio MW's that offering spinning reserve\fast start", but the percentage is not given and it is not clear if that % might change relative to other metrics of the portfolio such as load. CAC's goal in better understanding this metric is to ensure that it is appropriately including the reliability attributes that clean energy solutions can offer. In addition, now that FERC has approved the changes to MISO's thermal accreditation methodology, CAC would strongly recommend that those changes be included in addition to the seasonal reserve margin requirements.

- **Equity:** Given the high proportion of low-income ratepayers in CenterPoint's service territory and the disproportionate impact of emitting industries on its service territory, we would recommend a two-part equity metric that looks at low-income cost burdens and emissions exposure. We would propose the following:
    - First, a metric that measures whether emitting units in each portfolio are located in low-income and/or communities of color and how those overlap with other emitters in Southern Indiana. An example of this as it relates to peaker plants in New Mexico is given below.

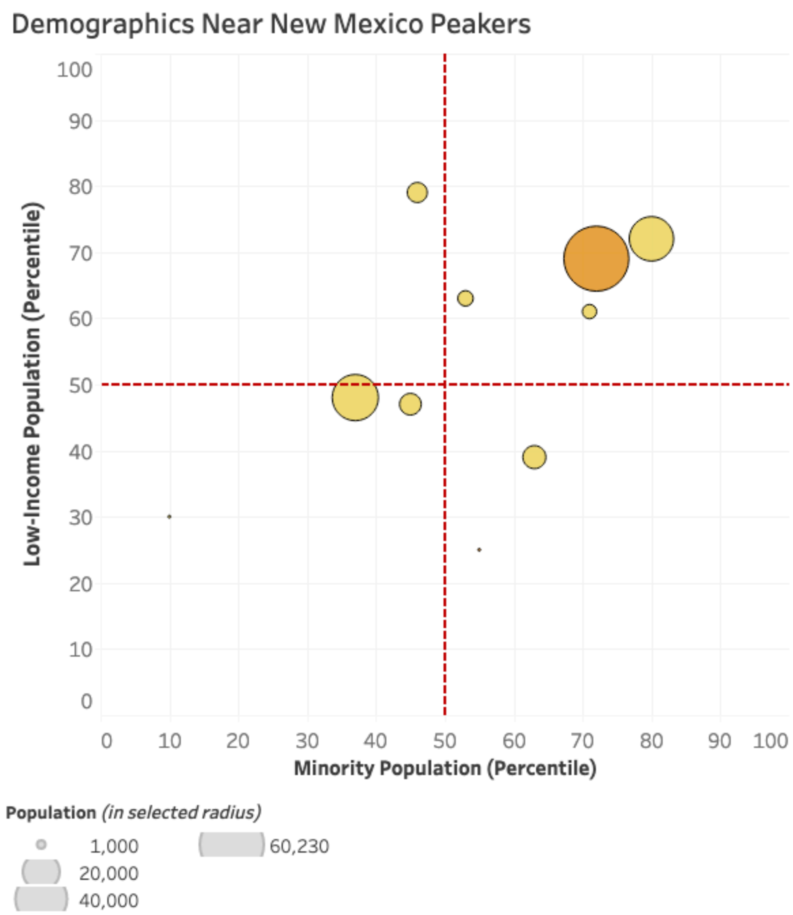


Figure 1. Demographics Near New Mexico Peaker Plants[1]

The circle size indicates the population within a given radius of the plant and the color, in this case, distinguishes between peakers at their own site versus those co-located with a combined cycle plant. For CenterPoint's purposes, we would recommend keeping the low-income and community of color axes, but changing the color coding to reflect the fuel burned at emitting units. We would note that a similar graph, but for all fuel types, could be used to identify some of the positive and negative impacts as well as the equity of those impacts of replacement generation once those locations are identified.

- Second, a metric that looks at the cost burden by census tract and could account for the bill impacts of community-solar projects that could be placed in those communities (since those are now eligible for a bonus Investment Tax Credit)

[1] https://www.psehealthyenergy.org/our-work/energy-storage-peaker-plant-replacement-project/new-mexico/

would be very useful. An example of this is given in a report looking at energy cost burdens as a percent of median household income in the state of Colorado.[2]

3 RFP

CAC appreciated having the opportunity to review and provide feedback on CenterPoint's draft RFP prior to its issuance and CenterPoint's willingness to incorporate our feedback. Given the significant volatility in markets over the past several months, as well as the enactment of the Inflation Reduction Act, which significantly changed tax credits for renewable energy and battery energy storage, we urge CenterPoint allow bidders the opportunity to update their project costs to ensure CenterPoint uses the most up-to-date information on resource costs as inputs in its IRP.

We look forward to reviewing the results of the RFP and the bid proposals submitted.

4 Environmental Update

Given the large cost increase in NOx allowances in 2022, CAC would appreciate hearing additional clarification on how CenterPoint will estimate the cost of NOx allowances in its IRP modeling. What NOx prices will CenterPoint use for future years, and how many purchases of allowances will CenterPoint need to make in future years?

5 DSM

5.1 Energy Efficiency "EE"

5.1.1 Market Potential Study "MPS"

CenterPoint engaged GDS Associates, Inc. ("GDS"), in January 2022 to perform a "refresh" of the most recent CenterPoint Market Potential Study ("MPS"), which was completed in 2019. Due to the nature of the refresh, the opportunities for stakeholder review and input were more limited compared to a full MPS. GDS and CenterPoint provided updates on the MPS development process periodically, but infrequently, at Oversight Board "OSB" meetings. While CenterPoint and GDS were generally receptive to feedback provided during OSB meetings, CAC would have preferred more frequent updates with opportunities for formal review and comment. The draft MPS results were shared publicly by CenterPoint at the IRP Public Stakeholder Meeting held on August 18, 2022, prior to CAC having the opportunity to review or comment on the draft findings. At this time, several CAC concerns remain outstanding regarding the treatment and bundling of EE resources within the IRP.

[2] *See* PDF page 26 of https://www.psehealthyenergy.org/wp-content/uploads/2022/01/Colorado-Energy-Affordability-Study_Full-Report.pdf

The MPS, once completed, will quantify the technical, economic, maximum achievable, realistic achievable, and program potential savings for the years 2025 through 2042. Each of these MPS scenarios is described as follows:

- **Technical Potential** is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end users to adopt the efficiency measures. Technical potential is only constrained by factors such as technical feasibility and applicability of measures.
- **Economic Potential** refers to the subset of the technical potential that is economically cost-effective, based on screening with the utility cost test ("UCT") as compared to conventional supply-side energy resources.
- **Achievable Potential** is the amount of 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, customer awareness and willingness to participate in programs, technical constraints, and other barriers the "program intervention" is modeled to overcome. The potential study evaluated two achievable potential scenarios:
    - **Maximum Achievable Potential** ("MAP") estimates achievable potential on paying incentives equal to up to 100% of measure incremental costs and aggressive adoption rates.
    - **Realistic Achievable Potential** ("RAP") estimates achievable potential with CenterPoint 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.

5.1.2 MPS Cost-Effectiveness Screening

The MPS economic potential cost-effectiveness screening was performed as described below by GDS:

> *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. Apart from 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.*

Utility non-incentive costs were included in the overall assessment of cost-effectiveness in the RAP and MAP scenarios. Non-incentive costs were calibrated to recent CenterPoint levels by sector and program and applied on a per-first year kWh basis.

A notable inconsistency with the IRP is that the MPS does not consider the avoided cost of carbon regulation. Multiple IRP scenarios, as presented by CenterPoint at the August 18 IRP Stakeholder Meeting, include carbon regulation. Had the MPS included a similar assumption for future carbon regulation, the UCT scores for all measures would have improved, thereby enabling additional measures (or programs) to be considered cost-effective. This inconsistency results in a smaller amount of savings being available for selection within the IRP.

5.1.3 MPS Forecasted Cost and Savings

CenterPoint has not yet made available to CAC the MPS modeling files nor the MPS IRP bundling. As such, we are unable to provide any comments on the reasonableness and accuracy of the MPS assumptions and calculations. During MPS development with other Indiana utilities, these resources have been made available to CAC and other stakeholders at multiple stages throughout the development process, and certainly before any draft results are shared publicly.

5.1.4 MPS Bundles for IRP Modeling

Energy Efficiency resources will be bundled and inputted into the IRP according to the following process, as provided by GDS at the August 18 IRP Stakeholder meeting:

1. EE Inputs will align with RAP Potential *(but adjusted from gross to net savings)*
2. EE Inputs will be provided over three vintages
    a. 2025-2027 (3 years)
    b. 2028-2030 (3 years)
    c. 2031-2042 (12 years)
3. For 2025-2027, EE Inputs will be bundled to closely resemble program offerings
    a. For remaining vintages, EE inputs will be aggregated at the sector level
4. EE Costs will include utility costs (incentives and non-incentive costs)
    a. Costs will be adjusted to recognize value of avoided lifetime T&D benefits

Based on discussions with CenterPoint and GDS during an IRP planning meeting held on August 2, CAC was under the impression that CenterPoint would be modeling bundles of savings from the MPS RAP scenario *and* the MPS MAP or an alternative "enhanced" version of RAP with elevated incentive levels. Instead, EE bundles were constructed only from the MPS RAP scenario. With this approach, MAP savings (or an "enhanced" version of the RAP) will be excluded from the IRP model entirely, and therefore will not be a selectable resource within Aurora and will not be allowed to compete with other resource options. This approach is problematic since it imposes limits on future EE potential based on existing program design, budget, and incentive levels. As a result, the MPS forecast as modeled in the IRP will not be independent of existing program constraints such as incentive budget.

5.1.5 Emerging Technology

CAC anticipates that the MPS analysis will include a limited number of emerging technology measures, consistent with the 2019 CenterPoint MPS and with studies completed by GDS for other Indiana utilities. For example, in another recent Indiana MPS, GDS included 32 measures (18 residential, 14 commercial & industrial) that were designated as emerging technology. CAC commends the inclusion of emerging technologies in an MPS, however, the relatively small number of measures results in a very limited impact. Many of the emerging technology measures included by GDS in other studies failed to pass the economic screen and therefore did not contribute to the achievable potential.

The nature of new emerging technology is such that high initial costs tend to fall as production volume and market adoption increase. The MPS analysis makes no accommodation for any emerging technology to be included in the later years of the analysis if/when the measure becomes cost-effective. New technologies are regularly being introduced, and many utility programs contribute to the market readiness of these emerging technologies through pilot programs and incentives. Failure to account for these technologies results in a conservative and unrealistic view of the potential savings.

As a point of comparison, the Consumers Energy 2021 Electric Energy Waste Reduction Potential Study, completed by Cadmus, evaluated over 200 emerging technology measures which were characterized and included in the model.[3] Ultimately, 170 unique measures were included in what Consumers Energy refers to as the "Transformational Scenario." The impact of this scenario was significant on the estimate of future achievable potential, as shown in Figure 2 below.[4] In years 3 through 9, emerging technologies account for roughly 20% of the achievable potential. In the later years of the Consumers Energy study, emerging technologies account for roughly two-thirds of the achievable potential. These results plainly demonstrate the significance of emerging technologies and highlight the importance of adequately accounting for them in a market potential study.

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[3] MPSC Case No. U-21090, Consumers Energy Co. Witness Garth, Exhibit A-81 available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Consumers-Energy-Electric-EWR-EE-Potential-Study-w-TransTech-Scenario-20210610.pdf

[4] Presentation by Consumers Energy, "Creating a Transformational Path to the Future of Energy Efficiency, Together!," available at https://www.michigan.gov/mpsc/-/media/Project/Websites/mpsc/workgroups/EWR_Collaborative/2022/Transformational-EWR-Together_CE_20220719-final.pdf

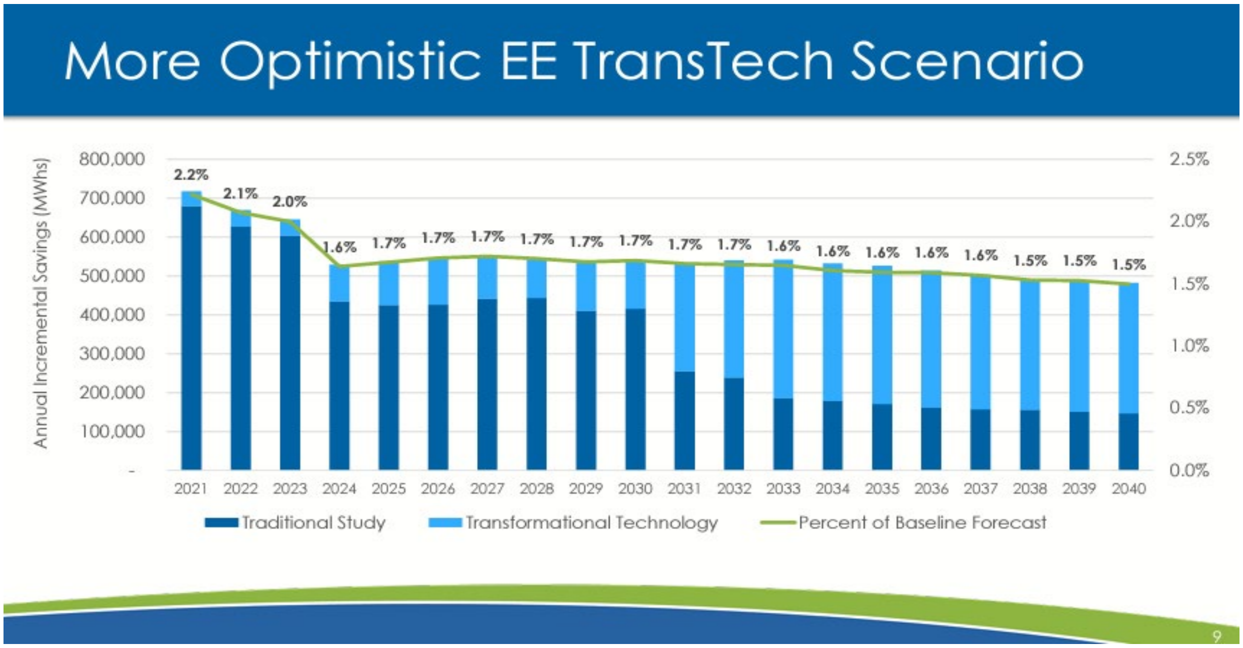

Figure 2. Consumers Energy Transformational Scenario

5.1.6 Demand Response

During a July 13, 2022 meeting with CenterPoint to discuss demand response, CAC asked that CenterPoint/GDS use the same methodology employed for the AES MPS to develop additional demand response options. CAC outlined several reasons why relying on an RFP to characterize DR opportunities would result in little to no meaningful data to use. For example, there is no meaningful DR aggregator community in southern Indiana, and industrial customers could not be expected to be experts in demand response programs themselves. To date, CenterPoint has not responded to this request, and we would reiterate its importance to ensuring that all cost-effective resources are available in the IRP modeling.

6 Load and Commodity Forecasts

6.1 Load Forecast

CAC appreciates CenterPoint's and Itron's presentation to stakeholders of its draft load forecasting methodology before finalizing the load forecast for the 2022-2023 IRP. CAC asks for clarity on the following items ahead of the preparation of the final load forecast:

1. How these data were calibrated to CenterPoint's electric service territory;
2. Have shorter weather periods been evaluated – e.g. 10-year or 15-year historical temperature data?;
3. Transparency on how the EIA electric vehicle forecast will be incorporated into the total energy and peak demand forecasts.; and
4. Whether Itron will incorporate the Inflation Reduction Act tax credits for electric vehicles.

In addition, CAC would like to understand the approach that will be used to forecast industrial load. Will Itron be responsible for that analysis, or will CenterPoint substitute its own forecast as it did in the previous IRP? If the latter, what will CenterPoint's methodology be, and what data will it rely upon?

6.2 Commodities Forecasts

CAC is extremely concerned that the reference case forecasts for natural gas and coal pricing are underestimating the costs of these fuels, as well as their price volatility. The natural gas and coal price forecasts assume a rapid return to low commodity pricing in 2023-2024, followed by a gradual increase in fuel prices, with no significant volatility, from 2025-2042.

The reference case fails to consider the current, record-high prices for both coal and natural gas and overall volatility in pricing that is an attribute of the status quo with these fuels. In that context, sustained high fuel costs are possible, yet it does not appear that CenterPoint will be modeling this. For instance, the U.S. is continuing to expand LNG capacity, which will result in increased exports of natural gas in the future as the U.S. provides larger quantities to places like Europe. The natural gas industry has also proven extremely reluctant to expand production despite high prices due to investor pressures to bring spending down. Likewise, coal mining companies are not opening new mines to meet short-term increased demand due to projected long-term industry decline, and coal transportation problems could continue to hamper deliveries, continuing upwards pressure on coal costs. The near-term natural gas and coal price forecasts predicting dramatic declines in prices therefore lacks credibility under current recognized market dynamics and should be rectified.

6.2.1 Natural Gas

All but one of the vendors is forecasting well below the current spot price for natural gas, which is currently approximately $9.04/MMBtu (see Figure 3).[5] Henry Hub futures are currently trading at approximately $5.00/MMBtu and above through first half of 2024. CAC recommends that CenterPoint update the Henry Hub projections to align more closely with the expected market conditions in the near term. CAC would also appreciate clarity on the methodology used to average the forecasts of the four vendors. For example, are the prices derived from a simple or weighted average?

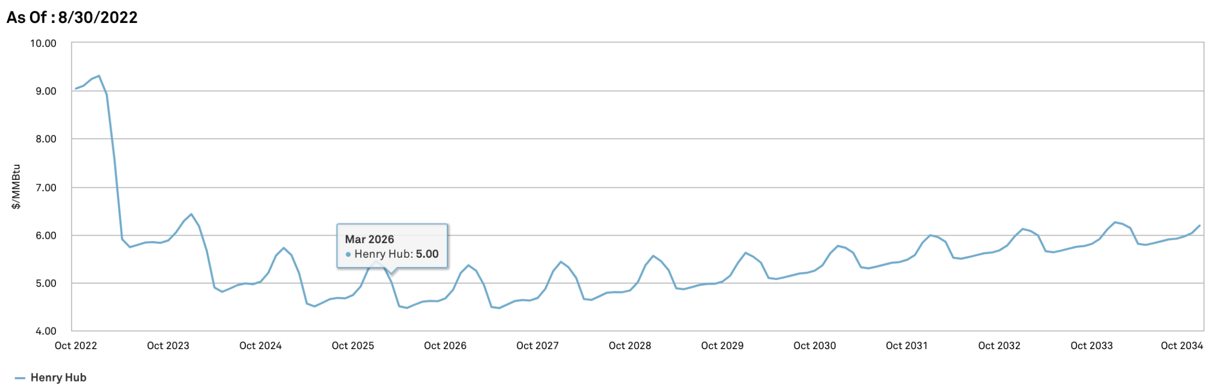

Figure 3. Henry Hub Natural Gas Futures as of 8/30/22

Two of the four coal price forecasts for the 2022-2023 IRP currently project coal prices to be below $3.00/MMBtu for the majority of the forecast horizon. Average weekly Illinois Basin coal traded at $8.04/MMBtu for the week of 8/26/2022.[6] By comparison, CenterPoint states its price for coal in 2022 was approximately $5.00/MMBtu. Three of the coal price forecasts do not exceed $3.00/MMBtu for most, if not all, of the planning horizon. CAC recommends CenterPoint update its coal price forecast to reflect the current state of coal prices.

The forecast for MISO Capacity prices has only two vendors. These forecasts start from different points, however, both forecasts converge on the same point over the forecast horizon. This may give less value to averaging these vendors. CAC ask for clarity on the limited number of vendors for MISO Capacity price forecasts as compared to other commodity projections presented at the stakeholder workshop. If additional forecasts are not available to CenterPoint, CAC recommends that CenterPoint consider scenario analysis rather than the averaging two forecasts. In either event, it may make the most sense to price capacity sales only in the production cost runs, so that the capacity price does not unduly influence the resource build.

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[5] *CME Group. Henry Hub Natural Gas*. https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.html. August 30, 2022.
[6] *Coal Markets. EIA*. https://www.eia.gov/coal/markets/#tabs-prices-2. August 31, 2022.

7 Resources

During the August 18, 2022, stakeholder meeting, CenterPoint presented several thermal and non-thermal resource options that would be modeled as new supply side resources in EnCompass. For new supply side resource options, we recommend that:

1. CenterPoint consider the resource screening analysis to determine if some of the new thermal options, such as supercritical or ultra-supercritical coal with CCS, be offered as a resource in the capacity expansion model.
2. Reflect the tax credits outlined in the Inflation Reduction Act ("IRA").
3. Consider modeling longer duration Lithium-Ion battery storage resources in addition to 4-hour storage resources given the tax credits for standalone battery resources under the IRA.

We would also recommend that in future workshops CenterPoint discuss any resource constraints that will be applied in EnCompass in addition to the declining ELCC values for renewable and battery storage resources that were noted on slide 77 of the stakeholder workshop. Will CenterPoint impose any annual or cumulative build limitations as constraints in its modeling? If so, what are those constraints?

8 Stochastic Modeling

It is our understanding from the information provided in the stakeholder workshop that CenterPoint is planning on replicating the stochastic modeling approach that was used in the 2020 IRP. Given the differences between Aurora and EnCompass, we had several follow-up questions to better understand how the stochastic modeling will be conducted:

1. How many stochastic iterations will be performed in EnCompass?
2. Will the stochastic modeling be applied to the production cost runs only?
3. What topology will be modeled in EnCompass? Will 1898 and CenterPoint be modeling a larger footprint than the CenterPoint system?
4. In the 2020 IRP, the stochastic modeling included capital costs as a stochastic variable but only in areas outside of the CenterPoint system. Is the plan to include capital costs as a stochastic variable? If so, we would strongly encourage CenterPoint remove this variable from the analysis because capital costs are uncertain, e.g., the impact of expanded tax credits are not volatile so it would very difficult to develop an appropriate probability distribution. We would recommend that capital costs be addressed through scenarios or sensitivities.

9 Reference Case

ACE Proxy and Carbon Price

CAC requests additional information on how the CO_2 ACE Proxy will be modeled in the IRP once that information is available. CAC observes that many utility IRPs are modeling the impacts of potential future climate policy through a forecast of escalating carbon prices included in their reference case.

10 Potential Scenarios

10.1 High Regulatory

CAC believes coal prices would be higher (not the same as in the reference case) in a high-regulatory environment. Environmental regulations would likely add costs. While demand for coal might be lower, providing downwards cost pressure, the industry will also be reducing supply by closing mines and reducing output, and transportation issues could persist, which will create upwards cost pressures.

In addition, because this scenario seems to be a high *environmental* regulatory scenario, we do not think that the cost of EE is likely to go up much. A comprehensive environmental policy would not just reduce carbon emissions, but also *incentivize* carbon reducing technologies. The recently passed Inflation Reduction Act is an example of this. While it did not include a carbon constraint, part of the Act's purpose is to reduce the cost of carbon abating technologies including on the demand-side. CAC believes the EE cost should at least be static in this scenario, if not go down and additional EE ought to be available to select (see Section 5).

10.2 FERC Order 2222 Scenarios

Will CenterPoint clarify if it will take efforts to incorporate Distribution System Planning into its IRP planning? FERC Order 2222 permits distribution-level resources (DER) to serve as wholesale capacity on a potentially unprecedented scale. This could have significant impacts on bulk-level system planning, which has been the traditional focus of the IRP process. CAC recommends that CenterPoint incorporate DSP into IRP planning as the penetration of DER increases. In particular, CAC would recommend that CenterPoint examine ways that FERC Order 2222 could encourage or bring additional value to low-income programs, energy efficiency programs, increased customer- and community-sited DER and other behind-the-meter programs across the service territory.

CAC encourages CenterPoint to evaluate the following in 2022 IRP:

- Identify current capacity hosting limits at the substation level
- Evaluate how much distributed capacity could be added at each substation without thermal or voltage violations
- Evaluate three scenarios:
  - Base Case in which the current level of solar and battery DER penetration is held constant,

    - Mid Case, in which the current level of solar and battery DER increases to the capacity hosting limit, and
    - High Case, in which the current level of solar and battery DER increases by 25% above the capacity hosting limit.
  - Estimate the potential attributes of increased DER participation:[7]
    - Avoided capacity value,
    - Energy and ancillary value,
    - Avoided transmission value, and
    - Voltage support value.

If it is not possible to identify a hosting capacity limit, then CAC would welcome an alternative proposal from CenterPoint that would enable the testing of differing levels of DERs. The cost of those DERs should reflect only the utility cost and account for participation impacts of the IRA.

[7] Zhou, Ella; Hurlbut David, and Xu, Kaifeng. *A Primer on FERC Order No. 2222: Insights for International Power Systems*. *NREL.* September 2021. https://www.nrel.gov/docs/fy21osti/80166.pdf

September 22, 2022

Matt Rice, Director, Regulatory and Rates, CenterPoint Energy
211 Northwest Riverside Dr., Evansville, IN, 47708

Dear Mr. Rice,

RE: Sierra Club recommendations in response to CenterPoint's first IRP meeting

Thank you for reaching out to solicit our input in CenterPoint Energy's 2022/2023 IRP Process. Below are our suggestions in response to the public stakeholder meeting on August 18th.

Locking in Coal Retirement Dates

Sierra Club's priority is to secure commitments from CenterPoint for retirement dates by 2030 for all of the Company's coal plants during this IRP process.

Culley Unit 2 and Warrick Unit 4

From the August 18th stakeholder meeting, we understand that CenterPoint pushed back the retirement date of Culley Unit 2 by three years (from 2022 to 2025) as a result of the high capacity clearing prices for MISO Zone 6 in the 2022/2023 Planning Resource Auction (PRA). During the extra years of operation, CenterPoint asserts that Culley Unit 2 will be valuable for its capacity even though it will seldom be dispatched, and that continuing to operate Culley Unit 2 will avoid the need for CenterPoint to pay high costs for additional capacity in the market. The Company presents a similar argument about extending its contract with Alcoa for Warrick Unit 4. We are concerned that this is a superficial analysis, and request that CenterPoint address the following questions before extending the operating dates of either unit:

- Does the Company believe that the recent high-capacity prices in the 2022/2023 PRA are indicative of likely future trends?
- Does the Company plan to issue a request for proposal (RFP) to see if it could meet short-term capacity needs at lower costs to ratepayers?

- Has the Company evaluated the capital and operation and maintenance (O&M) costs required to maintain Culley Unit 2 and Warrick Unit 4 until 2025? If extensive repairs are needed, costs could easily outweigh the capacity benefits of maintaining the plant.
- Will the Company commit to a cap on total funds that may be used for repairs and upgrades at its coal plants, especially the ones with near-term retirement dates?
- What actions is the Company taking to replace the coal capacity from these two units' capacity after the eventual closure of Culley Unit 2 and the end of its contract with Warrick Unit 4 to ensure there are no further delays in the units' retirements dates?

Culley Unit 3

We also request that CenterPoint commit to retiring Culley Unit 3 by no later than 2030, given recent developments in federal energy policy, including the Inflation Reduction Act (IRA), and the rapidly escalating costs of environmental compliance for CenterPoint's coal plants.

The price of NOx allowances under the Cross-State Air Pollution Rule (CSAPR) increased by a factor of 685 between 2020 and 2022, and allowance purchases will cost CenterPoint $22.5 million dollars this year, even as the Company runs its remaining coal units as cleanly as possible. The NOx emissions limits established by CSAPR will continue to tighten in future years, further driving up allowance prices. Because coal combustion is one of the most pollution-intensive methods for generating electricity, future environmental regulations, including regulation of greenhouse gas emissions, are likely to make Culley Unit 3 even more uneconomic.

And as the cost to operate Culley Unit 3 continues to rise, the cost of replacement resources are expected to fall. This is especially true after the enactment of the Inflation Reduction Act (IRA) in August. This will further erode the economics of maintaining Culley Unit 3 such that retirement by 2030, even with the effluent limitation guidelines upgrade costs already spent and sunk, will be the most economic course of action.

Revisiting Decision to Construct Natural Gas Plants

We also urge CenterPoint to reevaluate its plan to build two natural gas combustion turbine plants (CTs). Although CenterPoint has received Commission approval to construct the CTs (but it has not yet received approval for the pipeline needed to fuel them), it is under no obligation to construct them. Conversely, CenterPoint *does* have an obligation to its customers to re-evaluate the reasonableness of a project if market conditions change substantially. While changes in policy and market conditions occur regularly, and there is likely to always be some level of policy change or uncertainty during any resource planning process, the IRA is unique in the magnitude of its impact on renewable costs and the landscape of electricity utility resource planning as shown in Table 1 below.

Table 1: Renewable tax credits available to CenterPoint before and after IRA. Credits are now significantly larger, increasing the cost-competitiveness of renewables relative to coal and gas.

	CenterPoint 2019/2020 IRP tax credit assumptions[1]	**Current IRA tax credits**[2]
Solar PV	ITC: 2019: 30% 2020: 26% 2021: 23% After 2022: 10%	ITC: 30% base PTC: 2.5 cents/kWh 100%
Wind	PTC: 2.5 cents/kWh (in $2017) Stepping down… 2019: 40% 2020: 60% After 2021: 0%	PTC: 2.5 cents/kWh 100%
Battery Storage	-	ITC: 30%

Source: 2019/2020 IRP pages 175-177.

Note 1: Tax credits here reflect those included in the 2019 IRP. Tax credits were subsequently extended through 2025 after the IRP and prior to the IRA.
Note 2: 30% ITC and 2.5 cents/kWh PTC are all the base. Companies can get an extra 10% for siting in an energy community, and another 10% for use of domestic products

Revisiting the decision to construct the CTs is also especially important given the enormous cost and the risks the project places on ratepayers. These risks include the project's large capital cost, which poses a stranded asset risk if the plant becomes uneconomic before it is fully depreciated, the cost of the gas pipeline, and the cost of fuel, which is highly volatile.

Even before the IRA, CenterPoint's justification for the CTs was incomplete at best. The Company's own modeling from its 2019/2020 IRP — despite using unrealistically high renewables costs and low gas prices — showed that a portfolio with no CTs was lower cost than a portfolio that included two CTs (the High Technology Portfolio) in three out of five future scenarios. In all IRP scenarios, the portfolio with one CT was lower cost than the portfolio with two CTs. In four out of five scenarios, the second CT almost never operated, indicating that it is not needed for reliability and is at high risk of becoming a stranded asset.

As discussed above, the cost of NOx allowances has escalated rapidly since the 2019/2020 IRP was conducted. If 2022 prices continue, the net present value of allowances to balance emissions from the two turbines through 2039 ranges from $2.1 million to $46.8 million (depending on the capacity factor of the plants in each scenario). These costs further reduce the economic viability of the plants.

It makes sense that CTs do not appear as the lowest cost option in CenterPoint's modeling, because the availability of energy storage technologies renders them largely obsolete. This was true during the 2019/2020 IRP process and is even more true now. Operationally, battery storage is better suited to serving reliability needs and facilitating the expansion of renewables, because batteries respond to dispatch signals more quickly than CTs and can charge during periods of high renewable availability, reducing the need for curtailment. Now that battery storage is eligible for the investment tax credit (ITC), its capital costs are 30-50% lower than when CenterPoint performed its original analysis, further increasing its advantage over the costly combustion turbines and gas pipeline. Table 2 summarizes the cost of renewable generation (in 2022$) to CenterPoint before and after the IRA, assuming PPA financing for the ITC (and that the tax credit is not normalized over the life of the plant). The current costs would be even lower for projects eligible for tax credit adders under the IRA. We find that project NPVs are expected to fall around 25% for battery storage, 21-22% for solar PV, and 28-38% for wind, depending on capacity factor.

Table 2: Percent reduction in CenterPoint renewable project relative to the 2019/2020 IRP

	NPV (2025-2054) before IRA	**NPV (2025-2054) after IRA**	**IRA tax credit claimed**	**Percent Reduction**
Lithium ion battery (50 MW)*	$99 million NPV	$74 million NPV	Base ITC	25%
Solar photovoltaic (100 MW)	$177 million NPV	$139 million NPV	Base PTC 30% ITC	21.6% for PTC 21.1% for ITC
Wind in northern Indiana (38% CF) (200 MW)	$476 million NPV	$297 million NPV	Base PTC	38%
Wind in southern Indiana (28% CF) (200 MW)	$476 million NPV	$344 million NPV	Base PTC	28%

Source: Calculated from CenterPoint cost parameters provided in the Direct Testimonies of Matthew Rice and Michael Goggin in Indiana Utility Regulatory Commission Cause No. 45564
*Note: Battery storage NPV excludes VOM costs

Because CenterPoint will already be conducting EnCompass modeling as part of its IRP process, it would require minimal extra effort for the Company to include an unconstrained run evaluating the cost of the proposed CTs relative to replacement resources under current cost conditions. During the August 18th Stakeholder meeting, CenterPoint indicated that it would re-run its modeling to find the next optimal resources in the event that the gas pipeline wasn't approved by FERC. We repeat the question we posed at the meeting – why wait to perform the analysis if it could just be done proactively, and incorporate the updated renewable costs that resulted from the extension of the production tax credit (PTC) and ITC in the IRA?

Improving Modeling of Renewables and Climate Policies

With renewable costs lower than ever and the U.S. committed to a 50 percent reduction in greenhouse gas emissions by 2030, CenterPoint should use this IRP as an opportunity to explore a rapid buildout of renewable energy resources. The RFP lays the foundation for this effort, and CenterPoint should request that developers refresh their bids in light of the new tax credits available under the IRA. CenterPoint should also release the results of its RFP to stakeholders who have signed nondisclosure agreements (NDA).

Representing renewables in the IRP modeling

CenterPoint requested feedback on how to represent renewables in the IRP EnCompass modeling. We agree with the Company's plan to use RFP results to model resource cost assumptions in the near-term (provided the bids are refreshed based on the IRA impacts). For later years, CenterPoint should model generic resources, including both PPA and utility-owned projects based on transparent industry standard projections such as those provided by NREL, EIA or Lazard. Updating tax credit assumptions to match the IRA will be crucial to obtaining accurate results; this includes modeling solar and wind as eligible for either the PTC or ITC, and storage as eligible for the ITC, and modeling the incremental 10% adder for resources located in energy communities. The Company should clearly outline the assumptions that it makes regarding bonus credits related to wages, domestic content, and similar criteria. All calculations should be transparent, and CenterPoint should provide workbooks to stakeholders.

Carbon regulation

Regarding assumptions about carbon regulation in the IRP modeling, we are concerned with the Company's decision to use the Affordable Clean Energy (ACE) rule as the reference assumption for policy under Clean Air Act Section 111(d). Even after *West Virginia v. EPA*, the EPA has multiple possible avenues for establishing ambitious emissions limits for existing power plants under 111(d). ACE was a notoriously weak rule developed by a presidential administration that was hostile to climate policy, and it does not align with CenterPoint's stated commitment to align its operations with the Paris Agreement. The current administration is committed to emissions reductions, including a goal of 100 percent clean electricity by 2035, making it very likely that forthcoming power sector regulations will be stronger than ACE. To accurately represent this regulatory environment, CenterPoint should adjust its baseline policy assumptions. Additionally, the reference scenario should include new energy costs established by the IRA, as well as renewable energy builds to which CenterPoint is already committed.

Refining IRP Objectives and Evaluation Metrics

We appreciate CenterPoint's request for feedback on the objectives that it plans to pursue in its IRP, and have several suggestions for refining the metrics used to assess these criteria:

Affordability

CenterPoint lists affordability as its first objective and proposes to assess it using 20-year net present value revenue requirement (NPVRR). We agree that affordability should be a central objective of the IRP process, but NPVRR is an incomplete way to measure this goal. Affordability depends on distributional impacts as well as total cost to ratepayers. But NPVRR measures only aggregate cost, potentially masking impacts on low-income customers and other vulnerable groups. Low-income energy efficiency programs, and rate designs that target specific demographics and focus on bills and not rate can be critical in addressing affordability. To fully grasp the affordability of its portfolio options, CenterPoint should develop a methodology for assessing the impacts on each customer class and type separately.

Environmental sustainability

Similarly, environmental sustainability is a crucial IRP objective, but carbon dioxide intensity is potentially a misleading way to quantify it. What matters from the perspective of climate change is the overall quantity of greenhouse gas emissions added to the atmosphere, which depends both on electricity emissions intensity and the amount of electricity consumed. CenterPoint should quantify tons of carbon dioxide emissions rather than focusing only on emissions intensity. (When relevant, emission from greenhouse gasses besides carbon dioxide should also be included in this total.)

Reliability

For reliability, it appears that CenterPoint is weighing ancillary services (spinning reserve/fast start) equally with overall resource adequacy. Unless CenterPoint has particular reason to think that MISO ancillary service markets will be unable to provide sufficient ancillary services, UCAP obligations should be established as the primary reliability metric.

Risk minimization

Finally, we believe that the risk minimization objective should be expanded to include risks posed by fuel price volatility as well as market risk. Fossil fuel prices are inherently volatile, and portfolios that maintain reliance on natural gas and coal prolong customer exposure to price swings. CenterPoint should take this into account when comparing IRP portfolios.

Emphasizing Community Impacts in IRP Planning

Lastly, we encourage CenterPoint to expand its consideration of the community impacts of the portfolios it evaluates in the IRP. The CenterPoint electric service territory in Southwest Indiana is a sacrifice zone to polluting power, and while CenterPoint is not responsible for all of the emissions from the high concentration of coal-fired power plants in the region, its Brown, Culley and Warrick coal units are local contributors to air and water pollution. At the same time, CenterPoint customers are burdened with the highest electric bills in the state. CenterPoint should retire its fossil plants as soon as possible, rather than delaying retirement dates, and replace those units with affordable clean energy rather than more polluting, price-volatile fossil fuels. As the electric utility for the national hub of Super Polluters, CenterPoint could lead a clean energy transition in Southwest Indiana, and transform an energy sacrifice zone into a clean "energy community" utilizing incentives for coal communities in the IRA.

Devi Glick Senior Principal Associate Synapse Energy Economics dglick@synapse-energy.com	Wendy Bredhold Senior Campaign Representative, Indiana and Kentucky Beyond Coal Sierra Club wendy.bredhold@sierraclub.org
Lucy Metz Research Associate Synapse Energy Economics lmetz@synapse-energy.com	Tony Mendoza Senior Staff Attorney Environmental Law Program Sierra Club tony.mendoza@sierraclub.org
Jean Webb Energy Chair, Hoosier Chapter Sierra Club jeanwebb68@gmail.com	Robyn Skuya-Boss Lead Organizer, Beyond Coal Sierra Club robyn.skuya.boss@sierraclub.org

Cc (via email):

Dr. Bradley Borum, Indiana Utility Regulatory Commission, Director of Research, Policy, and Planning, bborum@urc.in.gov

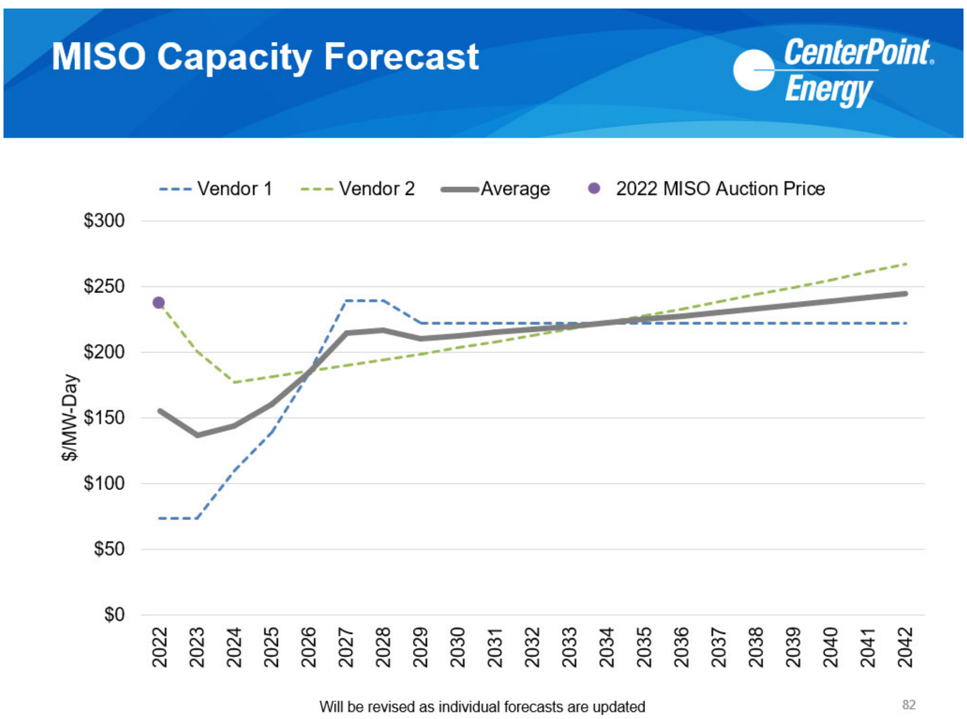
William Fine, Utility Consumer Counselor, Indiana Office of Utility Consumers Council, wfine@oucc.in.gov

Sierra Club Data Request Set 1 to CEI South
CEI South 2022/2023 IRP Response
October 12, 2022

1.1 Does the Company believe that the recent high-capacity prices in the 2022/2023 PRA are indicative of likely future trends?

Response: Yes. MISO released the 2022 OMS-MISO Survey Results on June 10, 2022. MISO pointed out in the survey that the MISO footprint is "projected to have a capacity deficit of 2.6 GW below the 2023 PRMR". Similar to the 2022 PRA results, these deficits are restricted to the North/Central Regions. Capacity deficits are projected to widen in subsequent years primarily driven by demand growth and the continued retirements of coal fired resources. As is described in CEI South's second IRP stakeholder deck and in the IRP Contemporary Issues Meeting on September 22, 2022, in a presentation from MISO, the RTO is seeing increased load and projecting a decline in accredited capacity through the 2040's.

As such, CEI South believes high-capacity prices will continue in future years as shown in the 1st IRP stakeholder presentation.



1.2 Does the Company plan to issue a request for proposal (RFP) to see if it could meet short-term capacity needs at lower costs to ratepayers?

Response: CNP did issue an RFP in May of 2022. The RFP produced a few capacity-only-bids but were not viable based on timing/pricing. CEI South has acquired capacity to satisfy most of its capacity needs for the 2023/2024 MISO planning year and continues to solicit capacity requests for the 2024/2025 planning year.

1.3 Has the Company evaluated the capital and operation and maintenance (O&M) costs required to maintain Culley Unit 2 and Warrick Unit 4 until 2025? If extensive repairs are needed, costs could easily outweigh the capacity benefits of maintaining the plant.

Response: CEI South has evaluated the projected capital and O&M cost to operate Culley Unit 2 through 2025 vs. purchasing replacement capacity and energy. [redacted]

1.4 Will the Company commit to a cap on total funds that may be used for repairs and upgrades at its coal plants, especially the ones with near-term retirement dates?

Response: No, this is not a commitment that CNP can make.

1.5 What actions is the Company taking to replace the coal capacity from these two units' capacity after the eventual closure of Culley Unit 2 and the end of its contract with Warrick Unit 4 to ensure there are no further delays in the units' retirements dates?

Response: CEI South continues to implement its generation transition plan of operating approximately 700 – 1,000 MWac of solar generation, 300 MWac of wind generation, and 460 MW of natural gas Combustion Turbine generation by the end of 2025 to replace the capacity from the A.B. Brown Units 1& 2 and F.B. Culley Unit 2 retirements in 2023 and 2025, respectively, as well as the exit of the Warrick Unit #4 Joint Operating Agreement to occur between 2023 and 2025.

IRP Public Stakeholder Meeting

October 11, 2022

Welcome and Safety Share

Richard Leger
Senior Vice President Indiana Electric

Safety share

Tips to Avoid Distractions While Driving

- Make adjustments before your get underway. Address vehicle systems like your GPS, seats, mirrors, climate controls and sound systems before hitting the road. Decide on your route, and check traffic conditions ahead of time.
- Secure children and pets before getting underway. If they need your attention, pull off the road safely to care for them. Reaching into the backseat can cause you to lose control of the vehicle.
- Put aside your electronic distractions. Don't use cell phones while driving – handheld or handsfree – except in absolute emergencies. Never use text messaging, email functions, video games or the internet with a wireless device, including those built into the vehicle, while driving.
- If another activity demands your attention, instead of trying to attempt it while driving, pull off the road and stop your vehicle in a safe place. To avoid temptation, power down or stow devices before heading out.
- As a general rule, if you cannot devote your full attention to driving because of some other activity, it's a distraction. Take care of it before or after your trip, not while behind the wheel.

CenterPoint Energy

Follow Up Information From First IRP Stakeholder Meeting

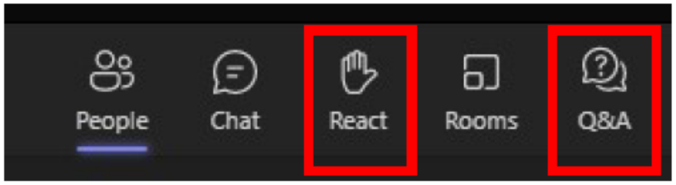
Matt Rice
Director, Regulatory and Rates

Agenda

Time		
8:30 a.m.	Sign-in/Refreshments	
9:30 a.m.	Welcome, Safety Message	Richard Leger, CenterPoint Energy Senior Vice President Indiana Electric
9:40 a.m.	Follow Up Information From First IRP Stakeholder Meeting	Matt Rice, CenterPoint Energy Director Regulatory & Rates
10:20 a.m.	All-Source RFP Update	Drew Burczyk, Consultant, Resource Planning & Market Assessments, 1898 & Co.
10:50 a.m.	Break	
11:05 a.m.	Draft Resource Inputs	Kyle Combes, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
11:40 a.m.	Lunch	
12:20 p.m.	Final Load Forecast	Michael Russo, Forecast Consultant - Itron
1:05 p.m.	Probabilistic Modeling Approach and Assumptions	Brian Despard, Project Manager, Resource Planning & Market Assessments, 1898 & Co.
1:50 p.m.	Break	
2:05 p.m.	Portfolio Development	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:35 p.m.	Draft Reference Case Modeling Update	Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
2:45 p.m.	Stakeholder Questions and Feedback	Moderated by Matt Lind, Director, Resource Planning & Market Assessments, 1898 & Co.
3:15 p.m.	Adjourn	

Meeting Guidelines

1. Please hold most questions until the end of each presentation. Time will be allotted for questions following each presentation. (Clarifying questions about the slides are fine throughout)
2. For those on the webinar, please use the "React" feature in Microsoft Teams (shown at the bottom of this page) to raise your hand if you have a question and we will open your (currently muted) phone line for questions within the allotted time frame. You may also type in questions in the Q&A feature in Microsoft Teams.
3. The conversation today will focus on resource planning. To the extent that you wish to talk with us about other topics we will be happy to speak with you in a different forum.
4. At the end of the presentation, we will open up the floor for "clarifying questions," thoughts, ideas, and suggestions.
5. There will be a parking lot for items to be addressed at a later time.
6. CenterPoint Energy does not authorize the use of cameras or video recording devices of any kind during this meeting.
7. Questions asked at this meeting will be answered here or later.
8. We will do our best to capture notes but request that you provide written feedback (concepts, inputs, methodology, etc.) at IRP@CenterPointEnergy.com following the meeting. Additional questions can also be sent to this e-mail address. **We appreciate written feedback within 10 days of the stakeholder meeting.**
9. The Teams meeting will be recorded only to ensure that we have accurately captured notes and questions from the meeting. The public meetings are not transcribed, and the recordings will not be posted to the website. However, Q&A summaries of our public meetings will be posted on www.CenterPointEnergy.com/irp.



Commitments for 2022/2023 IRP

- ✓ Utilize an All-Source RFP to gather market pricing & availability data
- ✓ Utilize EnCompass software to improve visibility of model inputs and outputs
- ✓ Will include a balanced risk score card. Draft to be shared at the first public stakeholder meeting
- Will strive to make every encounter meaningful for stakeholders and for us
- The IRP process informs the selection of the preferred portfolio
- Work with stakeholders on portfolio development
- Will test a wide range of portfolios in scenario modeling and ultimately in the risk analysis
- Will conduct a sensitivity analysis
- Will conduct technical meetings with interested stakeholders who sign an NDA
- Evaluate options for existing resources
- The IRP will include information presented for multiple audiences (technical and non-technical)
- Will provide modeling data to stakeholders as soon as possible
  - Draft Reference Case results – October 4th to October 31st
  - Draft Scenario results – December 6th to December 20th
  - Full set of final modeling results - March 7th to March 31st

Proposed 2022/2023 IRP Process

CenterPoint Energy

Stakeholder input is provided on a timely basis throughout the process, with meetings held in August, October, December, and March

1. Conduct an All Source RFP
2. Create Objectives, Risk Perspectives and Scorecard Development
3. Create Reference Case Assumptions and Scenario Development
4. Portfolio Development Based on Various Strategies, Utilizing Optimization to Create a Wide Range of Portfolios With Input From All Source RFP Data
5. Portfolio Testing in Scenarios, Focused on Potential Regulatory Risks
6. Portfolio Testing Using Probabilistic Modeling
7. Conduct Sensitivity Analysis
8. Populate the Risk Scorecard that was Developed Early in the Process and Evaluate Portfolios
9. Select the Preferred Portfolio

2022/2023 Stakeholder Process

CenterPoint Energy

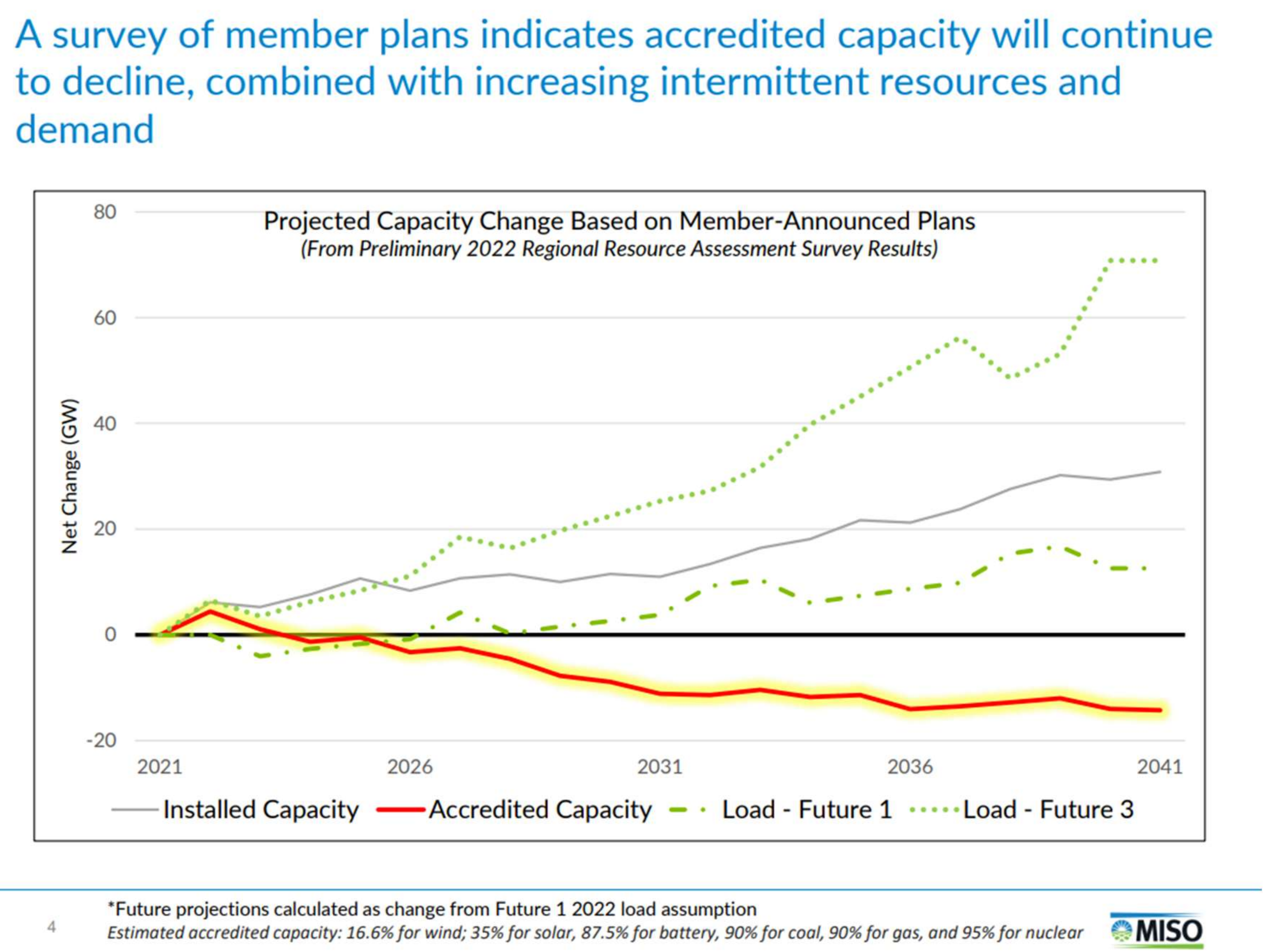
August 18, 2022	October 11, 2022	December 13, 2022	March 14, 2023
• 2022/2023 IRP Process • Objectives and Measures • Encompass Software • All-Source RFP • MISO Update • Environmental Update • Draft Reference Case Market Inputs & Scenarios • Load Forecast Methodology • DSM MPS/ Modeling Inputs • Resource Options	• All-Source RFP Results and Final Modeling Inputs • Draft Resource Inputs • Final Load Forecast • Scenario Modeling Inputs • Portfolio Development • Probabilistic Modeling Approach and Assumptions • Draft Reference Case Modeling Results[1]	• Draft Scenario Optimization Results • Draft Portfolios • Final Scorecard and Risk Analysis • Final Resource Inputs	• Final Reference Case Modeling • Probabilistic Modeling Results • Risk Analysis Results • Preview the Preferred Portfolio

[1] Draft modeling results will be shared on a CenterPoint Energy Technical modeling call on October 31, 2022 and supplemental slides will be posted to www.centerpointenergy.com/irp.

CEI South Expects Capacity Value to Remain High, Based on Recent MISO Communications

CenterPoint Energy

- Aggressive decarbonization strategies and accelerated policies are driving rapid change in our region
- As the evolution of the resource fleet accelerates, variability is increasing, and attributes required to reliably operate the system are diminishing
- Increased complexity is leading to an expanded scope and reprioritization across the elements of MISO's Reliability Imperative
- [MISO] must develop a coordinated transition plan to reliably navigate from the present to the future

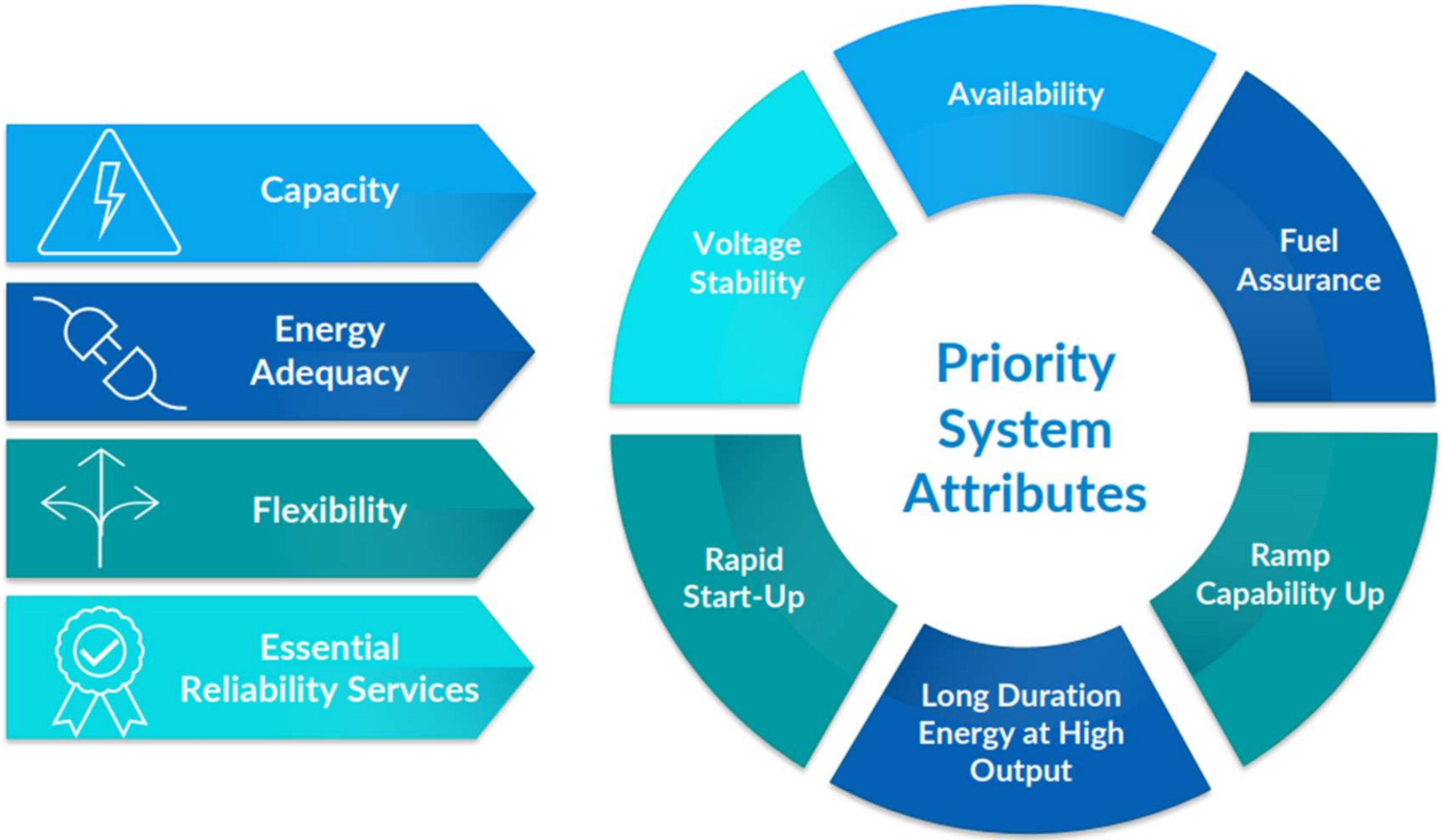


CTs Provide the Priority System Attributes MISO is Seeking

The region's energy landscape is evolving and will continue to evolve toward a more complex, less predictable future

- Primarily weather-dependent resources
- Risk-adjusted reserve margin requirements
- Less predictable resource outages or unavailability
- Less predictable weather
- Increasing scarcity of essential reliability attributes
- Increasing electric load
- Increasing importance of accurate load and renewable forecasting
- Focus on providing energy for the worst week in each season

Maintaining reliability with the changing resource portfolio and evolving risks also increases the importance of ensuring adequate attributes



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MISO

Stakeholder Feedback - Resources

Request	Response
Re-evaluate the CT's (combustion turbines) selected in the preferred portfolio of the 2019/2020 IRP	The CTs are the best resource available to ensure the reliability of the CenterPoint system, and the IURC approved their construction for that reason. CenterPoint will move forward with their construction to ensure its system remains reliable during the transition to renewables. Re-evaluating the CTs in this IRP would be a poor use of resources that CenterPoint believes could be better redirected to most efficiently perform the IRP
Allow the IRP to determine if Culley 2 retires in 2023 vs 2025	Culley 2 extension is contingent on IDEM NPDES approval. The capacity value Culley 2 is approximately $8 million at MISO Cost of New Entry (CONE). The unit is not expected to run much but helps CEIS to meet its MISO capacity obligation while new solar projects and CTs are brought online

Stakeholder Feedback - Resources cont.

CenterPoint Energy

Stakeholder Request	Response
Allow RFP respondents to update their proposals to account for the Inflation Reduction Act (IRA)	RFP respondents were given the opportunity to update their bids (updated results will be incorporated into the IRP)
Recommend that tax credits outlined in the Inflation Reduction Act are reflected in modeling assumptions	Updated RFP responses will be used to inform IRP assumptions
The MISO capacity price forecast only averages two vendors that converge over the planning period. Suggest scenario analysis rather than averaging the two forecasts so capacity price doesn't influence the resource build	Capacity prices are expected to remain high. During the portfolio development and capacity expansion phases of the modeling, the model will not allow revenues for excess capacity sales.
Provide stakeholders with access to RFP bid information	RFP bids will be shared using a process similar to past RFPs (requires NDA)
Provide a better understanding of how ACE proxy will be included	BAU Culley 3 assumes about $30M in efficiency upgrades. Based on efficiency studies conducted for the 2019/2020 IRP

Stakeholder Feedback - Resources cont.

CenterPoint Energy

Stakeholder Request	Response
Incorporate MISO's seasonal construct into the modeling analysis	The seasonal construct will be the basis for resource adequacy requirements, including seasonal accreditation for resources and seasonal planning reserve margin requirement
Consider the resource screening analysis to determine if some thermal options (supercritical and ultra-supercritical coal) should be removed as resource options to the model	CenterPoint will consider pending additional feedback from other stakeholders and model runtime. Screening may include more than coal resources
Consider modeling longer duration lithium ion (longer than 4 hours)	The tech assessment includes a long duration storage option. Also, the model will have the ability to select multiple blocks of 4-hour lithium-ion storage. There are limited economies of scale associated with moving from 4-hour to longer duration lithium-ion

Stakeholder Feedback - Resources cont.

Stakeholder Request	Response
Provide a better understanding of how ACE proxy will be included	BAU Culley 3 assumes about $30M in efficiency upgrades. Based on efficiency studies conducted for the 2019/2020 IRP

Stakeholder Feedback - Score Card

Stakeholder Request	Response
Use cumulative CO_2 equivalent emissions as a measure of environmental sustainability	CO_2 equivalent (stack emissions) will be added to the scorecard along with CO_2 intensity
Include a metric on the scorecard that quantifies whether resources in each portfolio are located in low-income or communities of color	New generation resources in the IRP analysis are not typically location specific; This is outside the scope of the IRP analysis
Add a fuel cost risk measure and objective to the scorecard	Cost Risk will be included in the scorecard, including both fuel risk and 95% percentile cost risk

Stakeholder Feedback - Score Card cont.

Request	Response
Add a metric to the scorecard that looks at the cost burden by census tract and could account for the bill impacts of community solar projects that could be placed in those communities	The IRP does consider energy cost by evaluating PVRR and fuel cost risk. Project location is generally outside the scope of the IRP analysis but is considered during project selection during which site-specific benefits are vetted. While outside the scope of the IRP, community solar should be compared with other potential assistance programs to determine which is more effective for providing bill assistance to low-income customers. Note that RFP responses did not include any community solar bids

Updated IRP Draft Objectives & Measures

CenterPoint Energy

Updates from the last meeting are shown in red

Objective	Potential Measures	Unit
Affordability	20 Year NPVRR	$
Cost Risk	Proportion of Energy Generated by Resources With Exposure to Coal and Gas Markets and Market Purchases 95% Value of NPVRR	% $
Environmental Sustainability	CO_2 Intensity CO_2 Equivalent Emissions (Stack Emissions)	Tons CO_2e/kwh Tons CO_2e
Reliability	Must Meet MISO Planning Reserve Margin Requirement in All Seasons Spinning Reserve\Fast Start Capability	UCAP MWs % of Portfolio MW's That Offer Spinning Reserve\Fast Start
Market Risk Minimization	Energy Market Purchases or Sales	%
	Capacity Market Purchases or Sales	%
Execution	Assess Challenges of Implementing Each Portfolio	Qualitative

Stakeholder Feedback - DSM

Request	Response
In the high regulatory scenario EE costs shouldn't increase but should be equal to the reference case or go down and additional EE should be available to select	A high regulatory scenario in which either codes & standards or carbon prices increase, this erodes away savings and increases the acquisition costs of energy efficiency savings. Decarbonization / Electrification scenario will potentially capture high-cost EE bins
Several questions regarding MPS and DSM	Will be addressed in separate meetings with CAC
Incorporate more than proposed 10-20 MWs of Industrial DR	CEI South will include 25 MWs of industrial DR as a resource. Currently, CEI South does not have any industrial DR customers.

Stakeholder Feedback - DSM cont.

Request	Response
MPS was inconsistent with the IRP in that the avoided cost of carbon regulation was not included which results in lower savings	Although including carbon cost in cost-effectiveness test may increase the savings potential, Indiana only recognizes the TRC (Total Resource Cost) as the cost-effectiveness test to implement non-low-income programs.
CenterPoint has not made available MPS & IRP modeling files	All modeling files were provided after incorporating feedback from CAC on 9/23/22
CenterPoint should include EE bundles that included an “enhanced RAP”	CenterPoint has now included an “enhanced RAP” for commercial

Stakeholder Feedback - DSM cont.

Request	Response
CenterPoint should adjust inflation for low-income bundles to allow this non-selectable bundle to include higher short-term inflation rates	CenterPoint has made this adjustment
CenterPoint should include more emerging technology in MPS similar to Consumers Energy	CenterPoint MPS does include emerging technology and will also leverage flex funding to capture emerging technology in future action plans
CenterPoint should include demand response using the same methodology as AES	CenterPoint has adopted the AES methodology and DR is now aligned with peers to incorporate indicative TOU pilots
Implement residential rate programs (critical peak piecing, TOU, etc.) soon	Plan to evaluate in the future through a pilot

Stakeholder Feedback - Inputs

CenterPoint Energy

Stakeholder Request	Response
Several questions regarding load forecast	Will be addressed later in this presentation
Provide data inputs and modeling files to stakeholders	CenterPoint is targeting to provide modeling information according to the schedule outlined in the first stakeholder meeting
Stakeholder concern that the reference case forecasts for natural gas and coal prices are underestimating the cost of these fuels and their potential volatility	The stochastic analysis will vary coal and natural gas prices to capture potential volatility
The reference case forecasts for coal and natural gas prices show a decline in the near term	These assumptions will be updated as new forecasts are available. Included in appendix
Recommendation to utilize Henry Hub futures in the near term to better align with current market conditions	CenterPoint is considering using NYMEX futures in the near term and will adjust long-term forecasts as available. See appendix for forecast schedule and NYMEX.

Stakeholder Feedback - Inputs cont.

Stakeholder Request	Response
In future meetings discuss resource constraints applied to the EnCompass model and ELCC curves for renewables and battery storage resources	Development of ELCC curves will be discussed in this meeting along with constraints
Coal prices should be higher than the reference case in the high regulatory scenario (not the same as the reference case)	Coal prices will be updated to be higher than reference case in the high regulatory scenario
Stakeholder concern that sustained high fuel costs are possible but the reference case does not take this into consideration	This will be captured in the scenario analysis. The Continued High Inflation & Supply Chain Issues scenario includes a coal and natural gas price forecast higher than the reference case

Stakeholder Feedback - Analysis

Stakeholder Request	Response
Several questions were asked around stochastic modeling	Will be discussed later in today's presentation
Implement distribution system planning (FERC Order 2222) into IRP modeling	CenterPoint continues to monitor the level of distributed resources on its distribution system. The current level of penetration does not warrant this level of detailed analysis at this time but could be evaluated in a future IRP analysis. Additionally, MISO is currently planning to incorporate FERC Order 2222 into its processes in 2030 pending FERC approval. As more information becomes available from MISO it can help shape how this analysis should be performed

Q&A

All-Source RFP Update

Drew Burczyk
Consultant, Resource Planning & Market Assessments
1898 & Co.

RFP IRA Updates

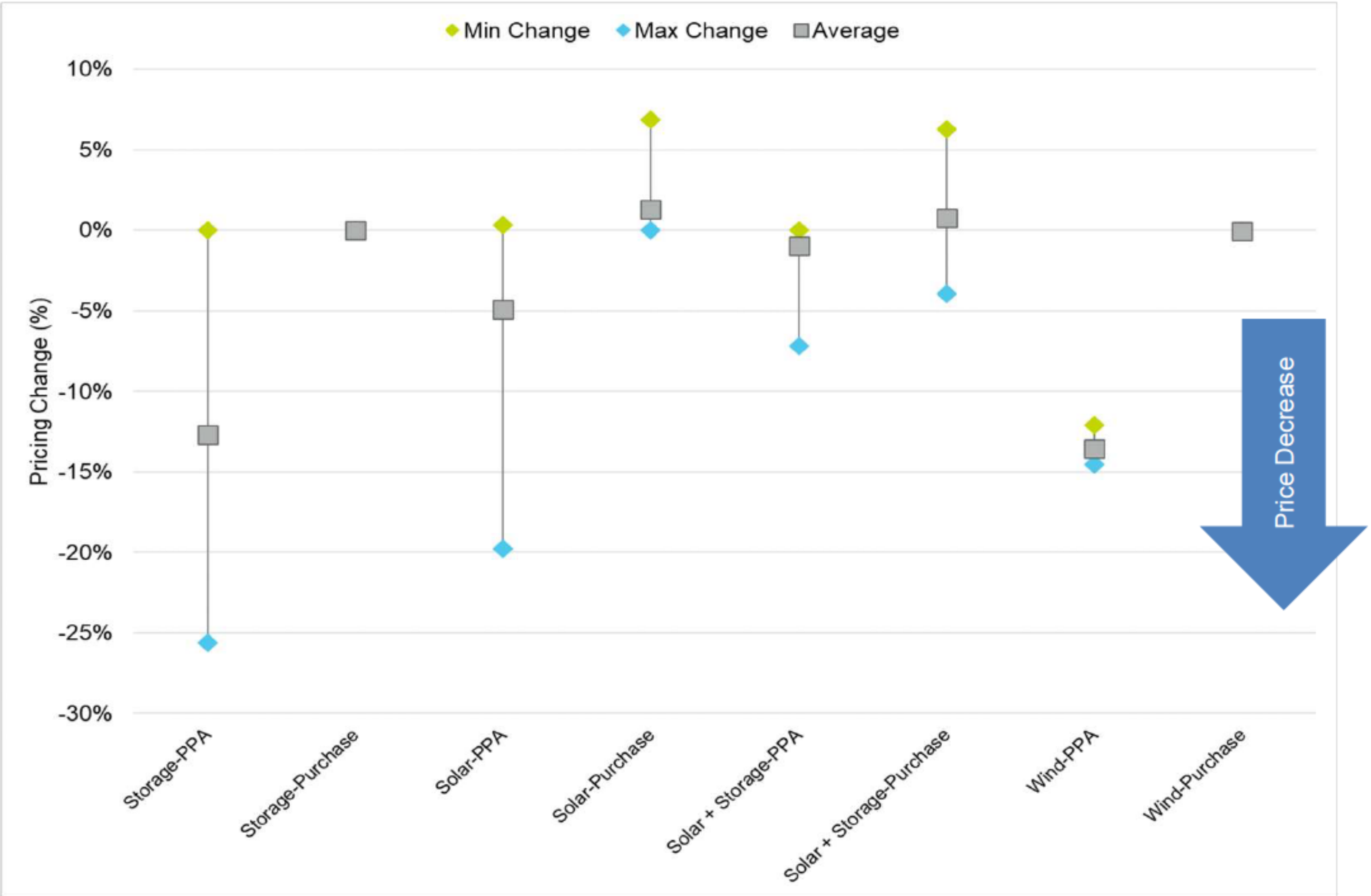
- The Inflation Reduction Act was signed into law August 16th.
- Stakeholder Meeting 1 occurred August 18th.
- Agreed with feedback and comments made during the Stakeholder meeting that updated costs from IRA could impact IRP modeling.
- August 23rd reached back out to bidders asking for updated pricing.
- This has delayed draft modeling results; A technical call to discuss draft results has been scheduled for October 31st with those that have signed a NDA. Supplemental slides will be posted to the www.CenterPointEnergy.com/irp

RFP IRA Updates

- 9 of 27 bidders submitted updated pricing to account for IRA changes.
- 77 Bids were returned with updated pricing.
  - 22 Solar bids
  - 46 Storage bids
  - 4 Wind bids
  - 5 Solar + Storage bids
- Example reasoning from bidders who did not update pricing:
  - Not applicable to proposal technology
  - Proposal pricing remains the same, offer was a BTA, tax credit would be monetized by CenterPoint
  - Benefits of IRA are offset by inflation and shortage in labor market

Pre vs Post IRA Pricing

Wide range of changes within certain technology groups. At a high level, the updated pricing received is not a 1:1 equivalent of IRA tax credit qualification.



Purchase prices do not account for tax benefits

Q&A

Draft Resource Inputs

Kyle Combes
Project Manager, Resource Planning & Market Assessments
1898 & Co.

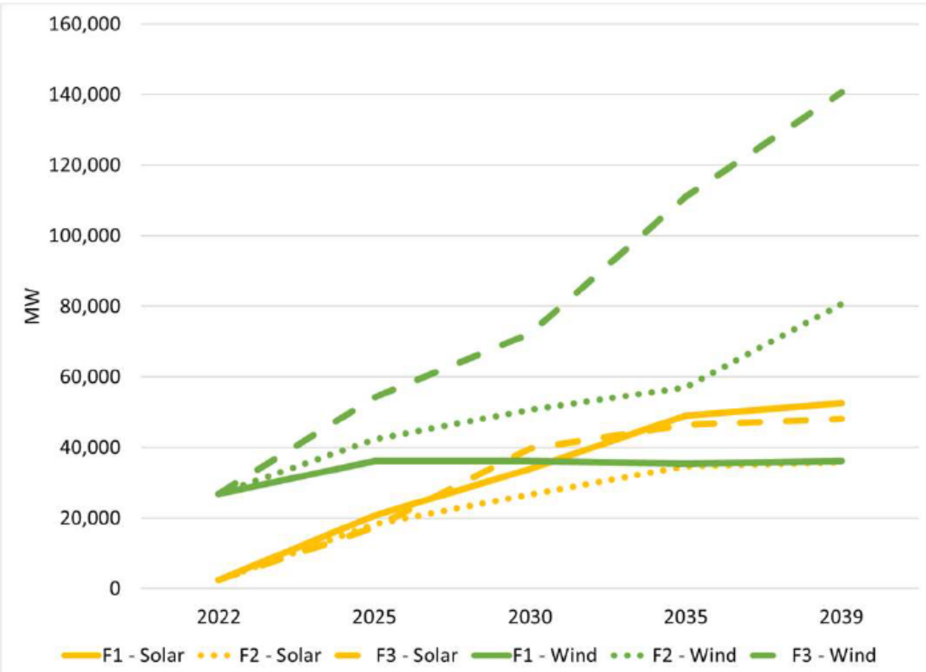
MISO Seasonal Resource Adequacy

CenterPoint Energy

- MISO is moving to a seasonal resource adequacy construct.
  - Winter - December, January, February
  - Spring - March, April, May
  - Summer - June, July, August
  - Fall - September, October, November
- Implementation beginning in MISO Planning Year 2023/24.
- This is new, and dynamic, we are working through these impacts and changes as more information becomes available.

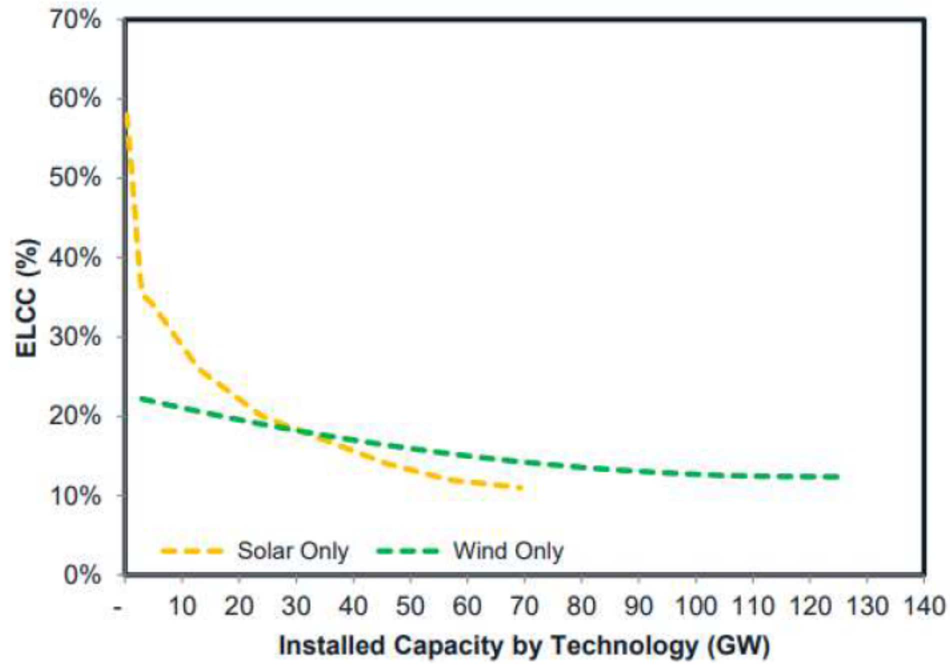
MISO Renewable Penetration Trends

MISO Installed Renewable Capacity



https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf

Effects of increasing installations

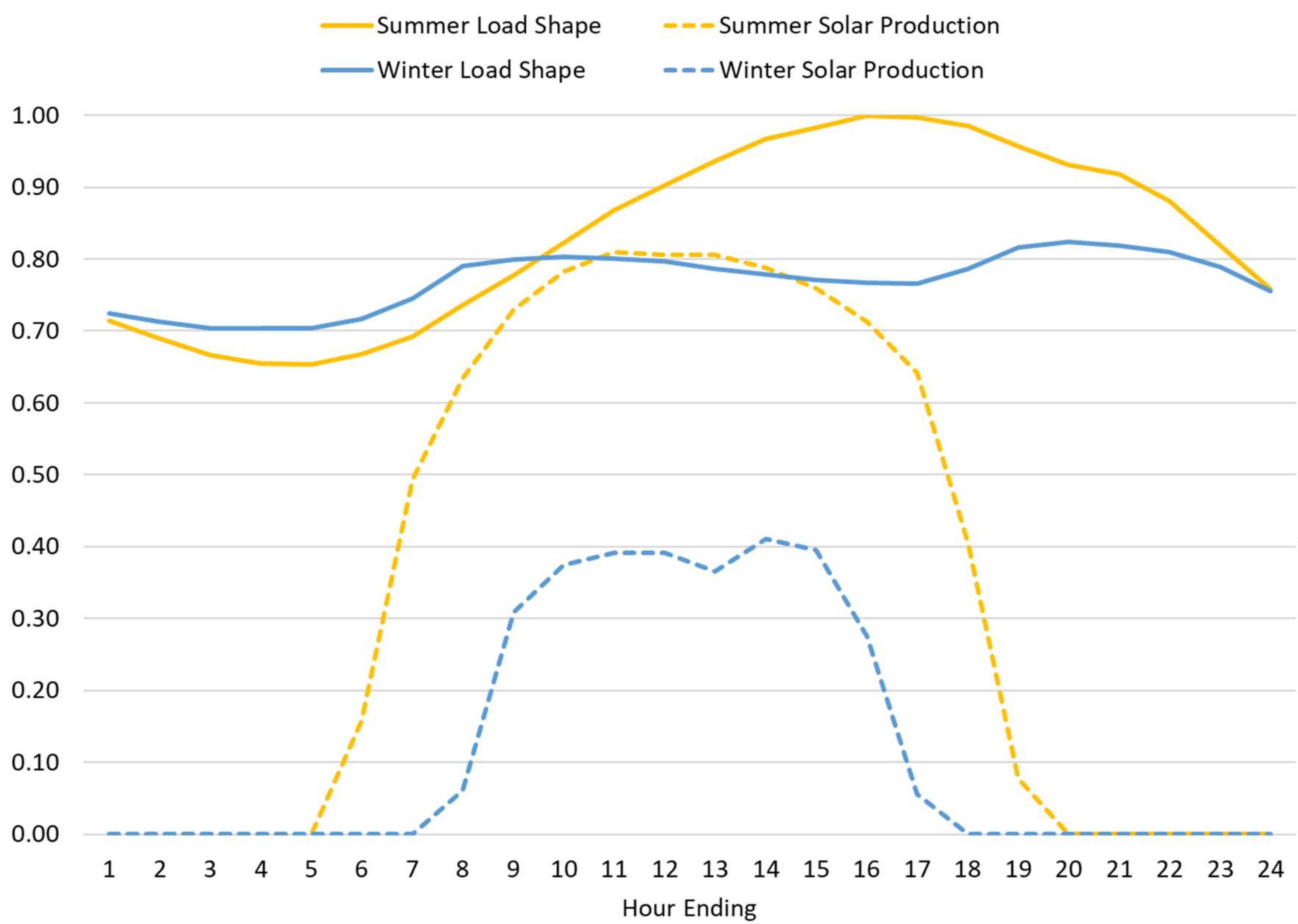


https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

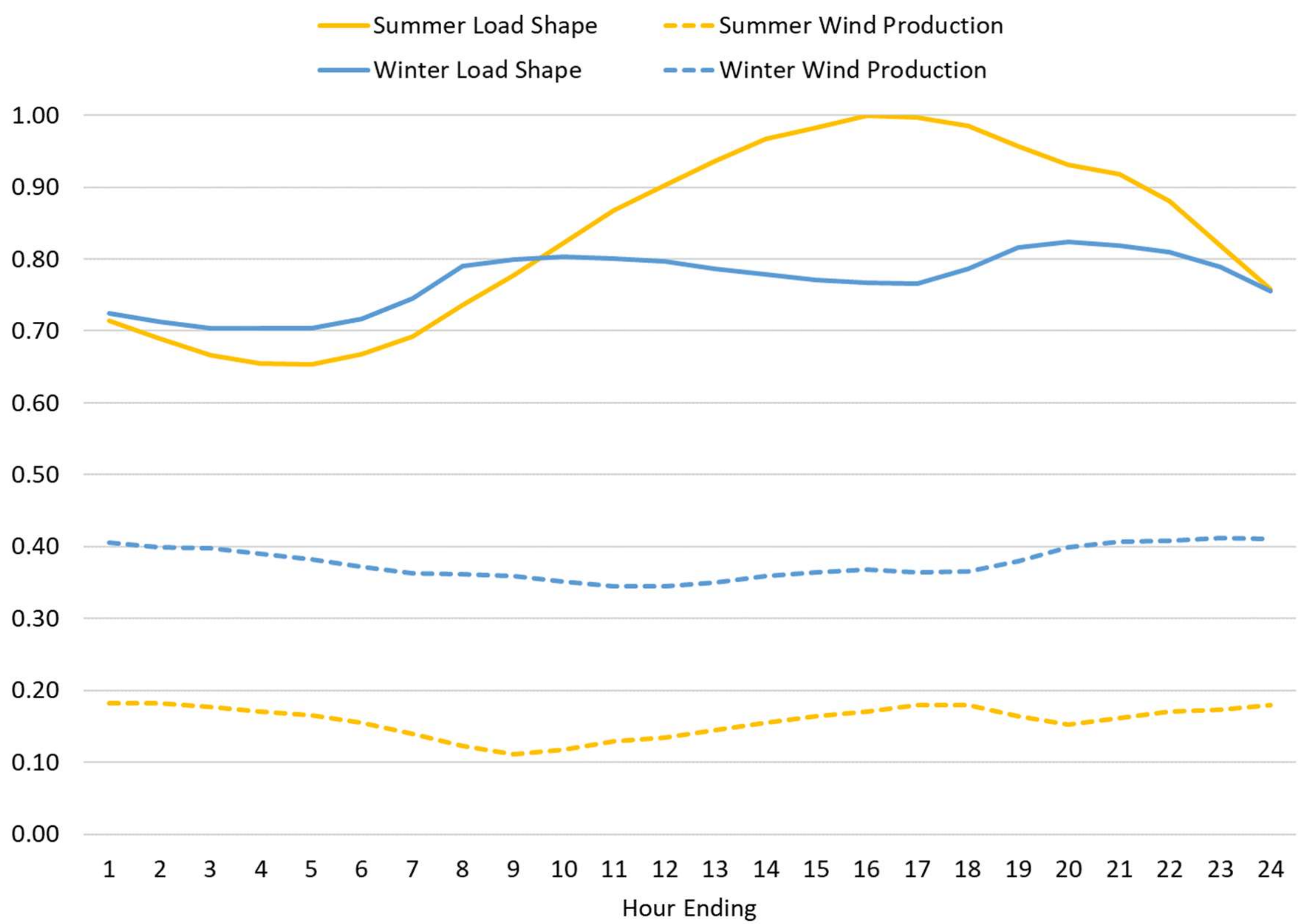
As installed capacity (ICAP) goes ⬆… Accreditable capacity (UCAP) goes ⬇

ELCC – Effective Load Carrying Capability

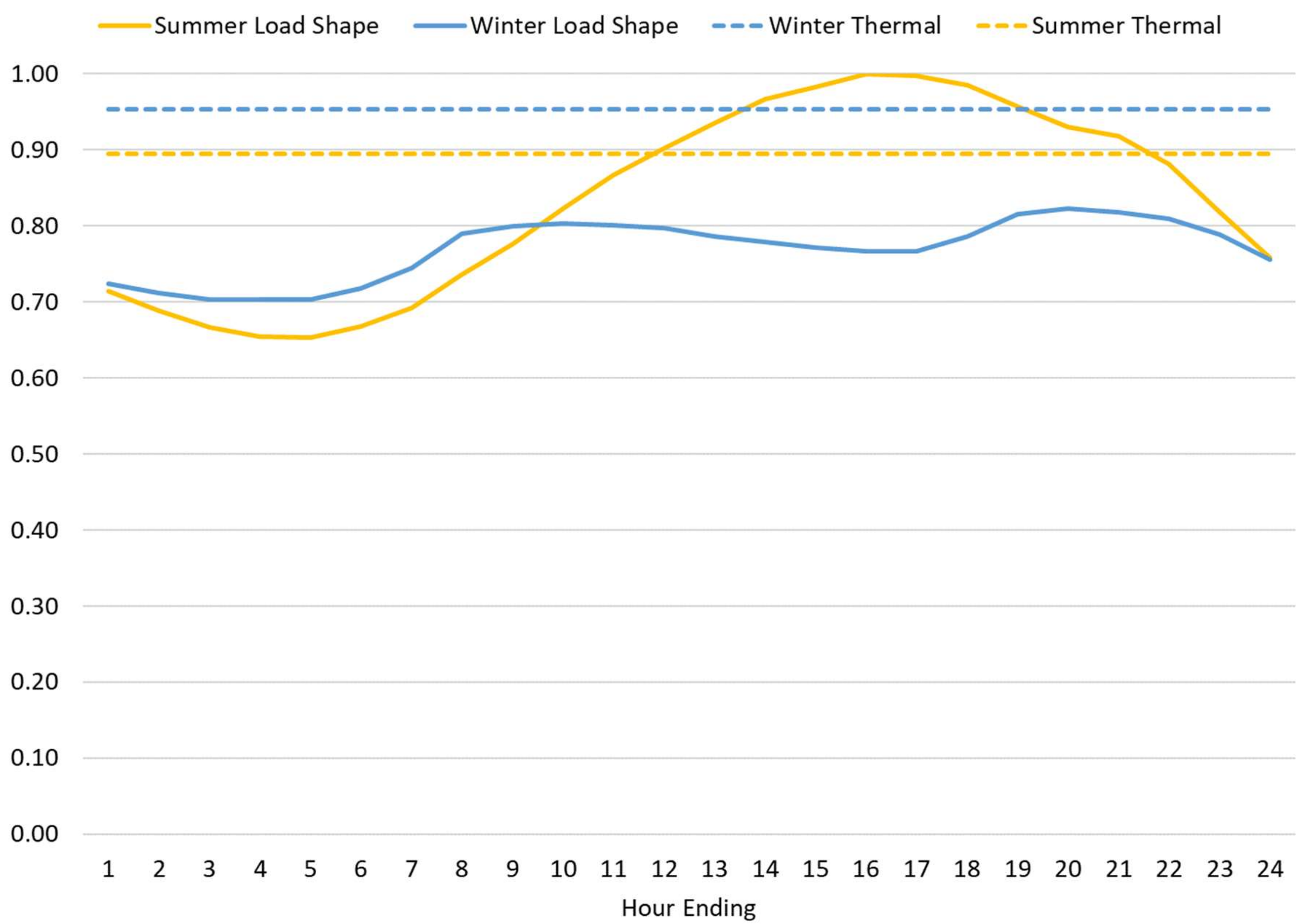
Solar Seasonal Differences



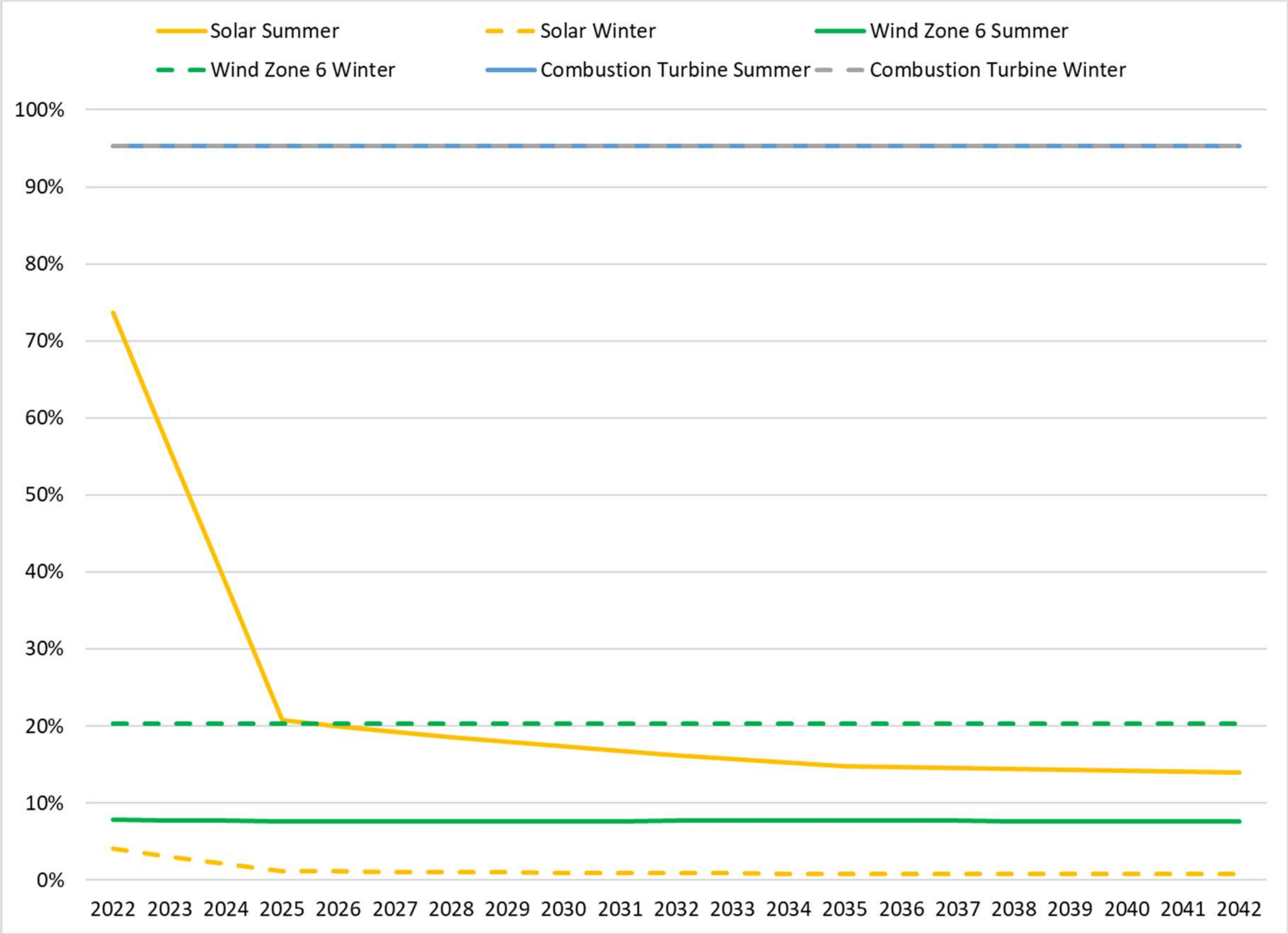
Wind Seasonal Differences



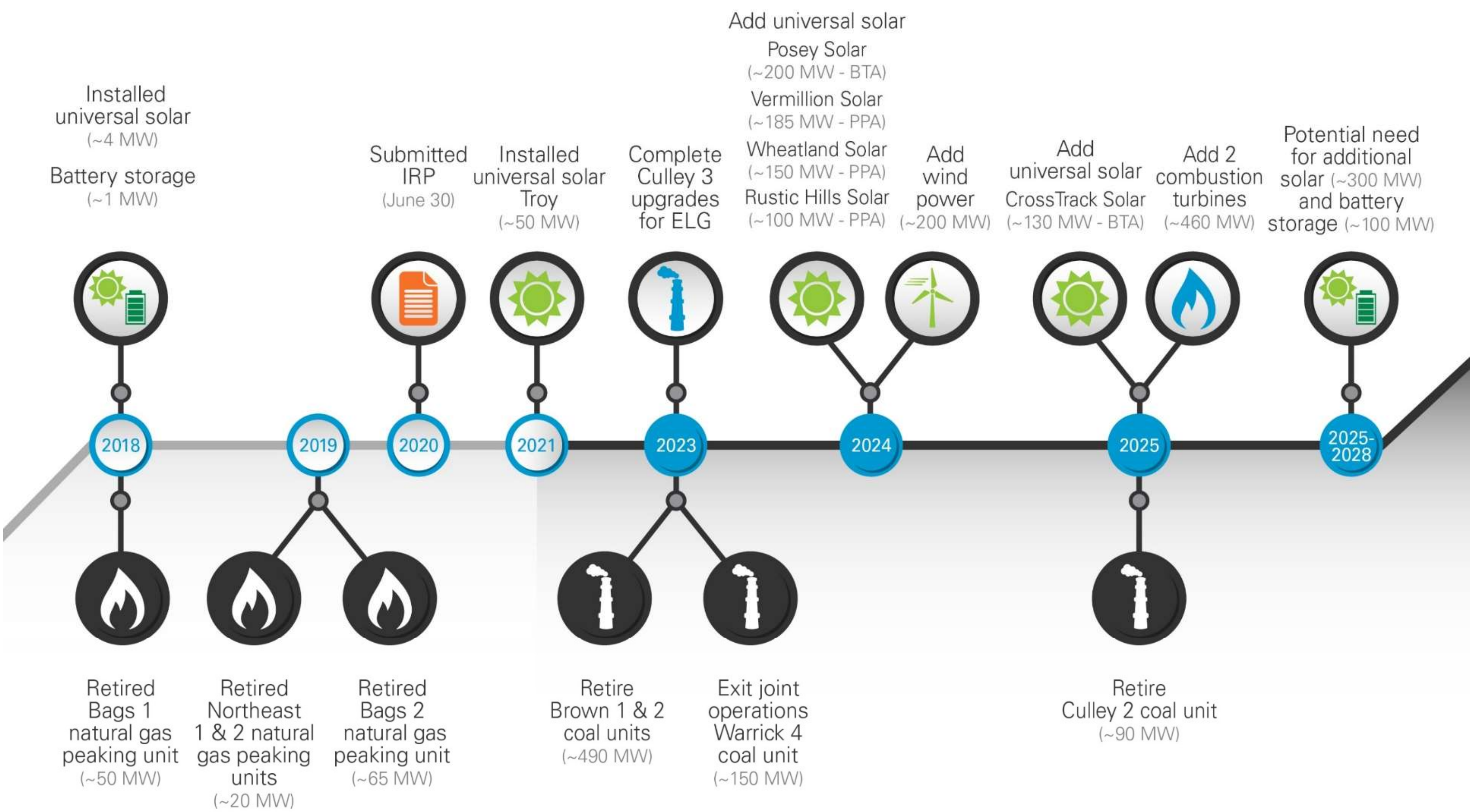
Thermal Seasonal Differences



Draft Projected Seasonal Accreditation

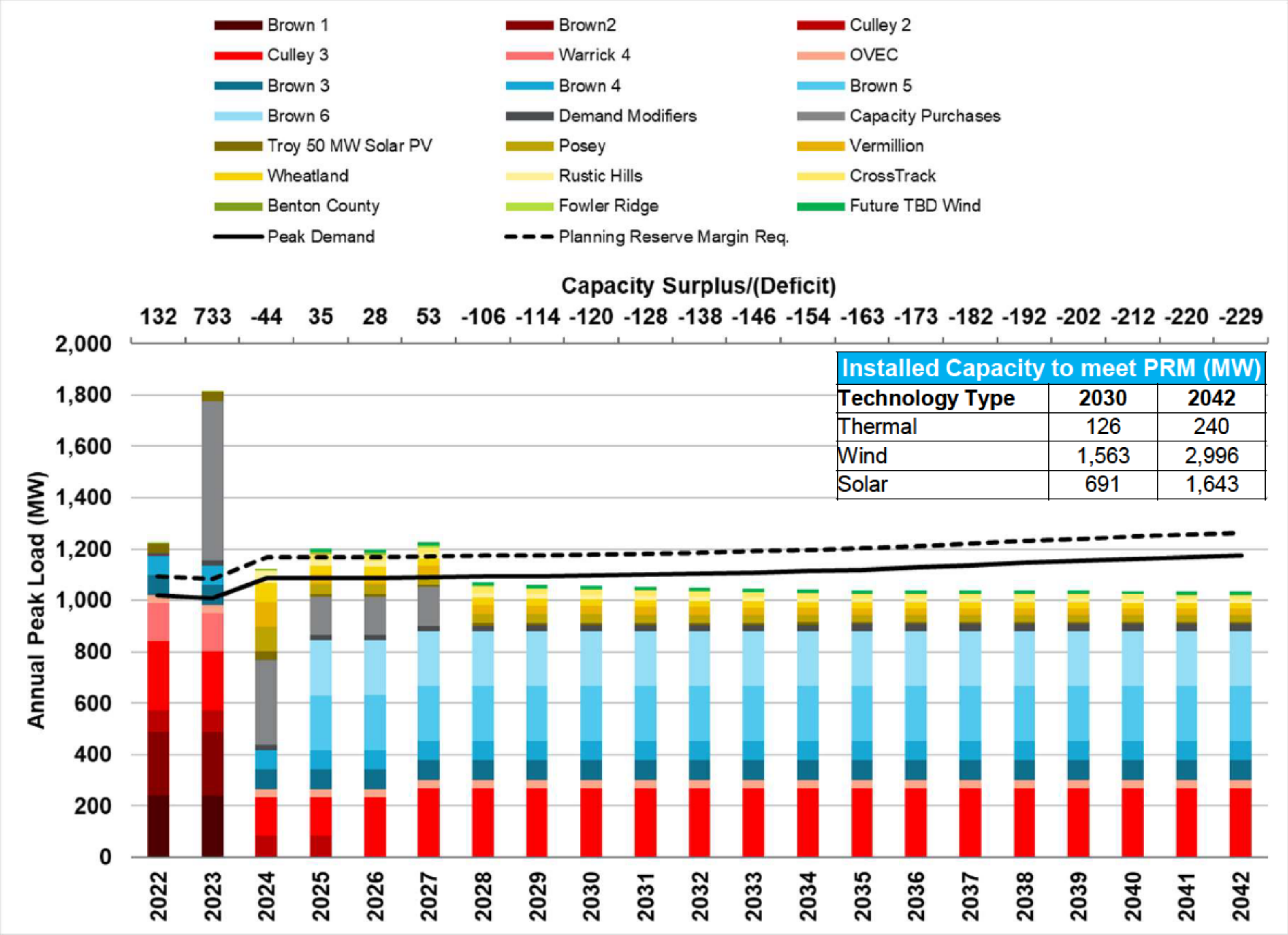


Generation Transition Timeline



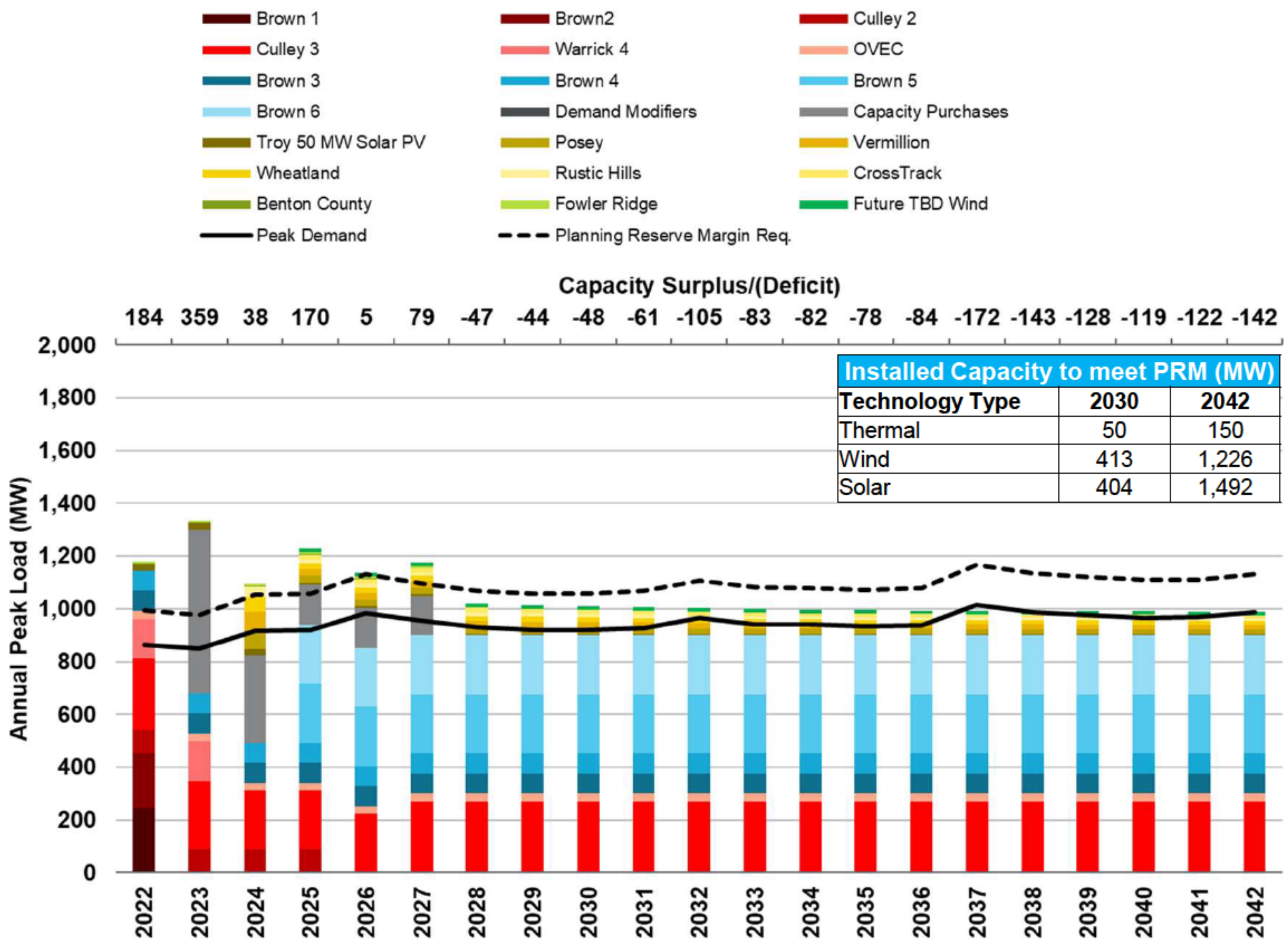
Bags = Broadway Avenue Gas Turbines
BTA = Build Transfer Agreement/Utility Ownership
ELG = Effluent Limitations Guidelines
MW = Megawatt
PPA = Power Purchase Agreement
IRP = Integrated Resource Plan

Balance of Loads and Existing & Planned Resources Summer



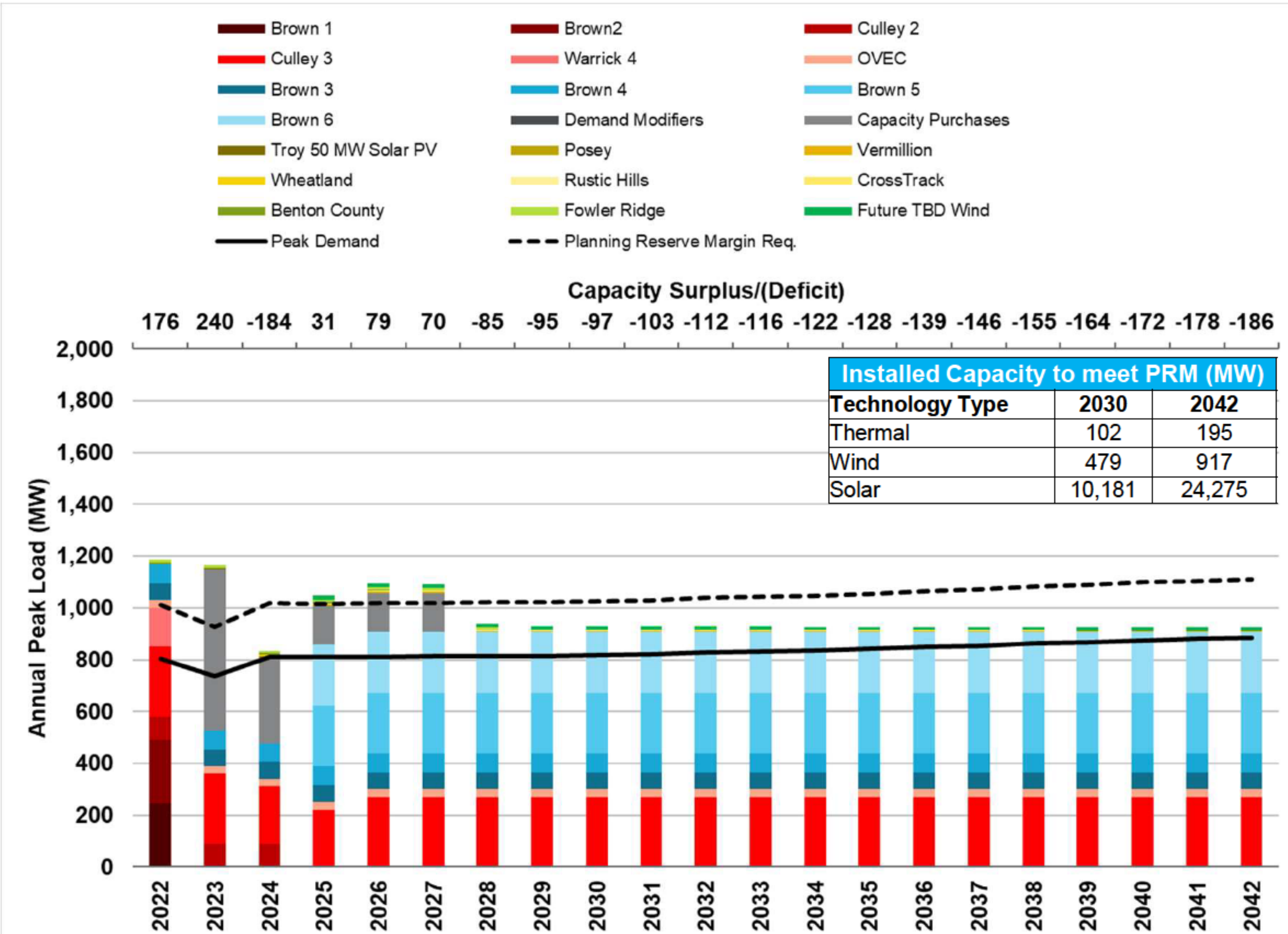
Installed Capacity to meet PRM (MW)		
Technology Type	2030	2042
Thermal	126	240
Wind	1,563	2,996
Solar	691	1,643

Balance of Loads and Existing & Planned Resources Fall



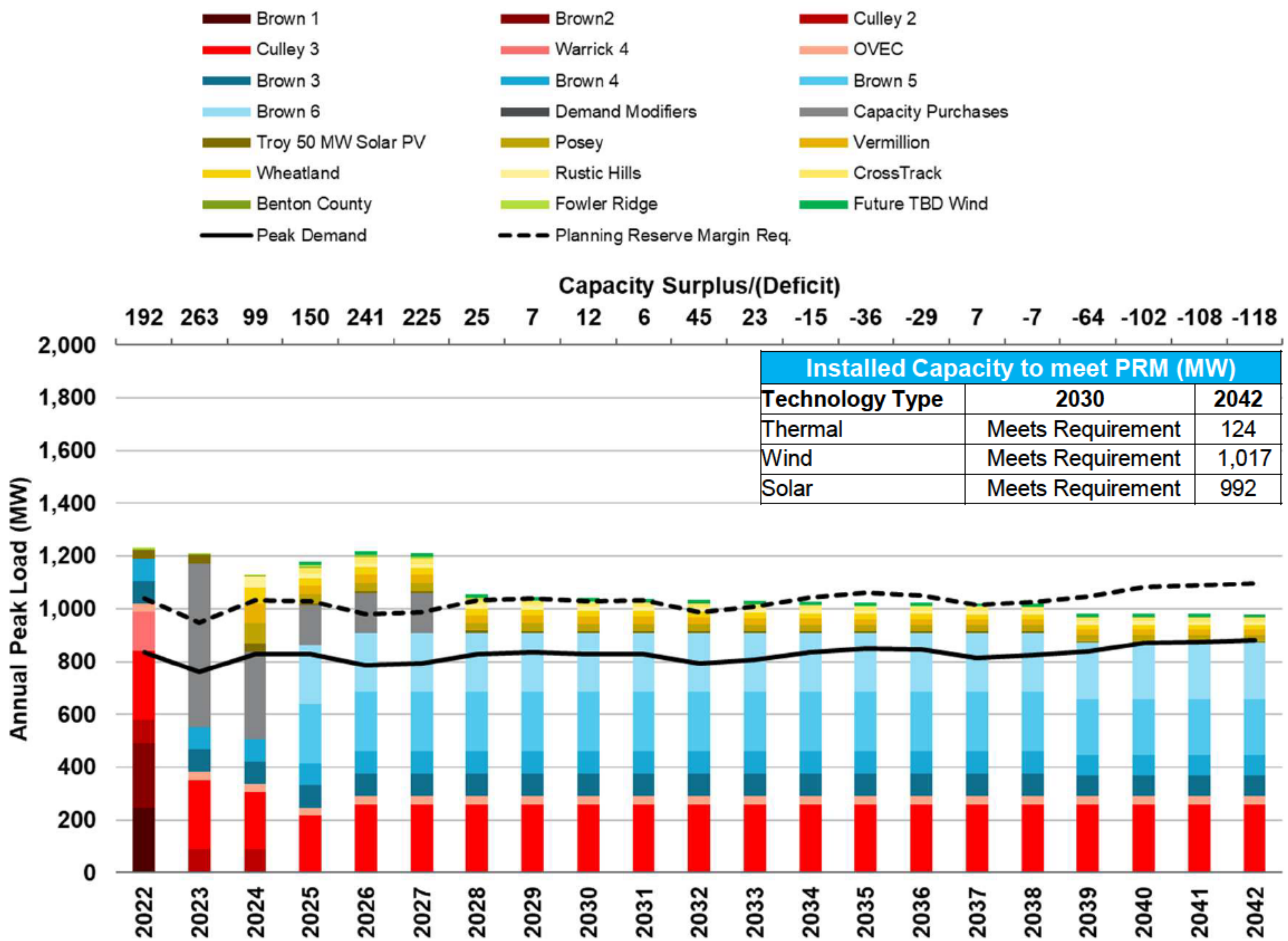
Installed Capacity to meet PRM (MW)		
Technology Type	2030	2042
Thermal	50	150
Wind	413	1,226
Solar	404	1,492

Balance of Loads and Existing & Planned Resources
Winter



Installed Capacity to meet PRM (MW)		
Technology Type	**2030**	**2042**
Thermal	102	195
Wind	479	917
Solar	10,181	24,275

Balance of Loads and Existing & Planned Resources Spring



Installed Capacity to meet PRM (MW)		
Technology Type	**2030**	**2042**
Thermal	Meets Requirement	124
Wind	Meets Requirement	1,017
Solar	Meets Requirement	992

Technology Assessment

- RFP bids were used to inform cost assumptions for near term resources.
- Technology Assessment was developed for future generation options.
- The costs from the Technology Assessment in combination with cost curve estimates are used for modeling resources out beyond the period where we have RFP bid data available.
- If no bid was received for a resource, TA costs are used as the default.

Technology Assessment Details

CenterPoint Energy

Examples of candidates for natural gas peaking generation:

Peaking	F-Class SCGT	G/H-Class SCGT	J-Class SCGT	6 x 9 MW Recip Engines	6 x 18 MW Recip Engines
Capacity (MW)	238	295	384	54	110
Fixed O&M (2022 $/kW-Yr)	$8	$7	$5	$28	$18
Total Project Costs (2022 $/kW)	$712	$699	$569	$1,756	$1,561

Examples of candidates for natural gas combined cycle generation:

Combined Cycle - Unfired	1x1 F-Class[1]	1x1 G/H-Class[1]	1x1 J-Class[1]
Capacity (MW)	363	431	551
Fixed O&M (2022 $/kW-Yr)	$12	$11	$8
Total Project Costs (2022 $/kW)	$1,278	$1,162	$962

Combined Cycle - Fired	1x1 F-Class[1]	1x1 G/H-Class[1]	2x1 J-Class[1]
Capacity (MW)	419	508	1,307
Fixed O&M (2022 $/kW-Yr)	$11	$9	$4
Total Project Costs (2022 $/kW)	$1,146	$1,036	$641

[1] 1x1 Combined Cycle Plant is one combustion turbine with heat recovery steam generator and one steam turbine utilizing the unused exhaust heat. 2x1 is two combustion turbines and 1 steam turbine.

Technology Assessment Details

CenterPoint Energy

Examples of candidate for nuclear generation:

Nuclear	Small Modular Reactor
Size (MW)	TBD
Fixed O&M (2022 $/kW-Yr)	TBD
Total Project Costs (2022 $/kW)	TBD

Examples of candidate for coal fired generation:

Coal	Supercritical Pulverized Coal with 90% Carbon Capture	Ultra-Supercritical Pulverized Coal with 90% Carbon Capture
Size (MW)	506	747
Fixed O&M (2022 $MM/kW-Yr)	$32	$32
Total Project Costs (2022 $/kW)	$6,659	$6,024

Examples of other thermal:

Other Thermal	Co-Gen Steam Turbine	2x1 F-Class CCGT Conversion	FB Culley 2 Gas Conversion	FB Culley 3 Gas Conversion
Size (MW)	22	717 / 257 incremental	100 / 0 incremental	287 / 0 incremental
Fixed O&M (2022 $/kW-Yr)	$323	$12	TBD	TBD
Total Project Costs (2022 $/kW)	$2,832	$691 / $1,990	$247	$107

Technology Assessment Details

CenterPoint Energy

Examples of candidate for wind generation:

Wind	Indiana Wind Energy	Indiana Wind + Storage
Base Load Net Output	200 MW	50 MW + 10 MW / 40 MWh
Fixed O&M (2022 $/kW-Yr)	$48	$49
Total Project Costs (2022 $/kW)	$1,845	$2,107

Examples of candidate for solar generation:

Solar	Solar Photovoltaic	Solar Photovoltaic	Solar Photovoltaic	Solar PV + Storage
Base Load Net Output	10 MW	50 MW	100 MW	50 MW + 10 MW / 40 MWh
Fixed O&M (2022 $/kW-Yr)	$60	$16	$11	$19
Total Project Costs (2022 $/kW)	$2,560	$1,856	$1,779	$1,910

Examples of storage:

Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Lithium-Ion Battery Storage	Long Duration Storage
Base Load Net Output	10 MW / 200 MWh	50 MW / 200 MWh	100 MW / 400 MWh	300 MW / 3,000 MWh
Fixed O&M (2022 $/kW-Yr)	$40	$38	$35	$19
Total Project Costs (2022 $/kW)	$2,500	$2,160	$2,020	$2,590

Capacity Cost Curve Summary

- Initial curve modeled from 2022 Annual Technology Baseline from NREL.
- Pricing of all RFP purchase options taken per technology type.
  - Pricing includes updates from the Inflation Reduction Act.
- Reference case follows the NREL curve shifted to match the aggregate bid pricing.
- The ‘Low’ curve is the interpolation from the reference case to the moderate NREL curve.

Capacity Cost Curves - Solar